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EVALUATION OF POLLUTION CONTROL IN FOSSIL FUEL CONVERSION PROCESSES. LIQUEFACTION: SECTION 2. SRC PROCESS

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Exxon Research and Engineering Company

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The report gives results of a review of the Solvent Refined Coal (SRC) process of the Pittsburg and Midway Coal Mining Company, from the standpoint of its potential for affecting the environment. It includes estimates of the quantities of solid, liquid, and gaseous effluents, where possible, as well as the thermal efficiency of the process. It proposes a number of possible process modifications or alternatives which could facilitate pollution control or increase thermal efficiency, and points out new technology needs.

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The process makes an appreciable amount of light gas which is recovered and cleaned up for use as plant process fuel, for example, in the reactor pre-heat furnace. A small amount of by-product naphtha is also formed. Raw materials used are summarized in Table 1, and product yields for the process are shown in Table 2.

Filter cake containing pre-coat is mixed with enough liquid product to form a slurry so that it can be fed to the gasification system. This stream contains nearly all of the ash in the coal feed, as well as some unconverted coal. The amount of liquid is set to give a slurry containing 50% wt. solid and 50% liquid.

The gasification system is a modification of the slagging type gasifier being developed with OCR/AGA funding (BI-GAS). For the modified system a slurry of ash and char is fed to a 2-stage gasifier, where it reacts with oxygen and steam at 1,700-3,000°F and 200 psig. The synthesis-gas leaves the upper 1700°F zone and contains mostly CO and hydrogen, in the ratio of 1.2 moles of CO per mole of H_2. Molten slag is removed from the lower 3000°F zone and is quenched in water for disposal.

Low BTU gas from the gasifier is cooled, scrubbed, and passed through acid gas removal. Part of it then goes directly to the coal liquefaction reactor and the remainder is shifted and scrubbed to produce pure hydrogen which is used for hydro-treating part of the liquid product to make the lower sulfur fuel oil.

In addition to the process facilities described there are auxiliary facilities needed such as the oxygen plant for gasification and utilities including steam, electric power, cooling water, and waste water treating. Also, a sulfur plant is included to process gases from the acid gas removal systems. This makes a high purity sulfur by-product, and has tail gas clean up facilities to meet environmental requirements.

One aspect of coal liquefaction that raises important environmental questions is that the product contains a large amount of oxygen and nitrogen compounds. To the extent that these are in fuel products, the major effect may only be on NO_x production during combustion. However, the water layer is separated after intimate contact with the oil, and will contain considerable amounts of these compounds that must be either removed as by-products, or destroyed.

One conventional approach is to extract chemicals, such as phenols, from the water layer using a suitable solvent (3). The phenols might then be sold, or burned. In the present design the method used for treating waste water is to extract phenols, etc. by using a heavy oil stream consisting of hydrotreated product. The extract is then recycled to hydrogenation where phenols and other unwanted materials are destroyed.

EPA-650/2-74-009-f

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LIQUEFACTION: SECTION 2. SRC PROCESS

by

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1. SUMMARY

The Solvent Refined Coal (SRC) process of the Pittsburg & Midway Coal Mining Company has been reviewed from the standpoint of its potential for affecting the environment. The quantities of solid, liquid and gaseous effluents have been estimated, where possible, as well as the thermal efficiency of the process. For the purpose of reduced environmental impact, a number of possible process modifications or alternatives which could facilitate pollution control or increase thermal efficiency have been proposed, and new technology needs have been pointed out.

2. INTRODUCTION

Along with improved control of air and water pollution, the country is faced with urgent needs for energy sources. To improve the energy situation, intensive efforts are under way to upgrade coal, the most plentiful domestic fuel, to liquid and gaseous fuels which give less pollution. Other processes are intended to convert liquid fuels to gas. A few of the coal gasification processes are already commerically proven, and several others are being developed in large pilot plants. These programs are extensive and will cost millions of dollars, but this is warranted by the projected high cost for commercial gasification plants and the wide application expected in order to meet national needs. Coal conversion is faced with potential pollution problems that are common to coal-burning electric utility power plants in addition to pollution problems peculiar to the conversion process. It is thus important to examine alternative conversion processes from the standpoint of pollution and thermal efficiencies and these should be compared with direct coal utilization when applicable. This type of examination is needed well before plans are initiated for commercial applications. Therefore, the Environmental Protection Agency arranged for such a study to be made by Exxon* Research & Engineering Company under contract EPA-68-02-0629, using all available non-proprietary information.

The present study under the contract involves preliminary design work to assure that conversion processes are free from pollution where pollution abatement techniques are available, to determine the overall efficiency of the processes and to point out areas where present technology and information are not available to assure that the processes are non-polluting.

All significant input streams to the processes must be defined, as well as all effluents and their compositions. This requires complete mass and energy balances to define all gas, liquid, and solid streams. With this information, facilities for control of pollution can be examined and modified as required to meet Environmental Protection Agency objectives. Thermal efficiency is also calculated, since it indicates the amount of waste heat that must be rejected to ambient air and water and is related to the total pollution caused by the production of a given quantity of clean fuel. Alternatively, it is a way of estimating the amount of raw fuel resources that are consumed in making the relatively pollution-free fuel. At this time of energy shortage this is an important consideration. Suggestions are included concerning technology gaps that exist for techniques to control pollution or conserve energy. Maximum use was made of the literature and information available from developers. Visits with some of the developers were made, when it appeared warranted, to develop and update published information. Not included in this study are such areas as cost, economics, operability, etc. Coal mining and general offsite facilities are not within the scope of this study.

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* Prior to June 1, 1974 Exxon Research and Engineering Company conducted business under the name Esso Research and Engineering Company.

Our previous studies in this program to examine environmental aspects of fossil-fuel conversion processes covered various methods for gasifying coal to make synthetic natural gas, low Btu gas, and/or liquid products. Reports have been issued on the Koppers, Synthane, Lurgi, CO_2 Acceptor, and COED processes (1,2,3,4,5). The present report extends these studies to include conversion of coal to clean boiler fuel that is low in sulfur and ash, using the Solvent Refined Coal (SRC) process being developed by the Pittsburg & Midway Coal Mining Company.

Some consideration has been given previously to environmental aspects of the SRC liquefaction process in several papers presented at an EPA symposium. One of these (34), "Environmental Factors in Coal Liquefaction" presented a quantitative engineering analysis, including performance of the biological oxidation system (biox). This was shown as giving 94% removal of ammonia, 95% removal of phenols, and 99% removal of phosphorous. However, the cooling tower and boiler blowdown streams, amounting to over half of the total waste water, were indicated to contain up to 10 ppm chromate, which would be extremely toxic to the culture that is depended upon to carry out biological oxidation. Pretreatment to thoroughly remove chromium will be needed. Also, cyanides, and particularly thiocyanates have been shown to be inhibitors and to resist biodegradation (29). While disposal of solid sludge from the biox system was not mentioned, provision is needed (with odor control), for example by incineration. The amount of such sludge would be sizeable, considering that the 600 gpm of blowdown is indicated to contain up to 15 ppm phosphate, 99% of which is removed by biox and thereby incorporated into cellular material.

We wish to acknowledge the information and assistance provided by EPA and the Pittsburg & Midway Coal Mining Company. To a large extent, the study has been based on an earlier, detailed engineering study prepared by the Ralph M. Parsons Company (11).

3. BASIS AND PROCESS DESCRIPTION

3.1 Basis

An alternative to converting coal to clean gas fuel is to liquefy it, and at the same time remove most of the sulfur and ash which pose major environmental problems if the coal is burned directly without adequate controls. Several processes are under development for carrying out this liquefaction. Some of these use a hydrogenation catalyst to speed up the reaction and allow high conversion. Such processes are being developed by Hydrocarbon Research Inc., the Bureau of Mines, and others. Another approach is to use a hydrogen donor liquid. This consists of an aromatic fraction of the product which is hydrogenated to form naphthenes, and then recycled to the coal liquefaction reactor where the hydrogen is transferred to the coal. The advantage of this route is that hydrogenation is done under relatively clean conditions, with the ash and metals in the coal excluded so that they do not foul the hydrogenation catalyst. Still another approach is to add hydrogen gas directly to the reactor without adding a catalyst, and accept the low conversion that is obtained for such a non-catalytic operation. The SRC process being developed by Pittsburg & Midway Coal Mining Company is of this type (6,7,8). The product is reasonably low in sulfur and quite low in ash so that it should be suitable as a clean boiler fuel. It is solid at room temperature and might be handled in this form, or it could be heated above the melting point and handled as a liquid. The advantage of this non-catalytic route is that there is no catalyst to foul, and hydrogen consumption is low compared to processes making synthetic crude. Production of hydrogen is a very large item of cost in coal liquefaction.

The product still is high in nitrogen (over 1%) and special attention must be given to the nitrogen oxides problem on burning it. Development work is under way on means to reduce NO_x formation by controlling the combustion conditions. Also, techniques are being developed to remove NO_x from flue gases by conversion to NO_2 which is then scrubbed out, or by reaction with ammonia to form nitrogen.

Early studies on the SRC liquefaction process were made by Chem Systems and by Stearns Roger (9,10), but these included hydro-cracking of the heavy product to make light liquids or synthetic crude. This is not now considered to be the preferred application. A more recent study by the Ralph M. Parsons Company (11) is based on making primarily a heavy product and is therefore used as a guide in our environmental evaluations. Their study did include some hydrotreating such that 1/3 of the heavy product has a sulfur content of 0.2%, versus 0.5% on the heavier fraction. Current emission regulations for liquid fuels correspond to about 0.6% sulfur content for fuels having the heating value of the SRC product.

An interesting feature of the process described by Pittsburg & Midway Coal Mining Company is that synthesis-gas can be used in the reactor instead of pure hydrogen. It appears that the water-gas shift reaction occurs at reaction conditions of about 850°F and 1000 psig., and perhaps the coal ash is catalytic for this reaction, and also for liquefaction. Of course, sufficient water or steam must be added for the shift conversion. Use of synthesis-gas is said to be practical on Western coals which are more reactive, but it is not recommended on Eastern coals.

Studies by The Ralph M. Parsons Company indicate that there is little or no economic advantage to using synthesis-gas rather than pure hydrogen since the CO must be shifted one place or another and the CO_2 removed by scrubbing. The use of hydrogen has the advantage of much higher hydrogen partial pressure in the reactor for a given total operating pressure. As far as overall material and heat balances are concerned, it makes little difference which path is used as the same amount of shifting and CO_2 scrubbing is required for either case. Therefore, our environmental studies are based on the Parsons numbers for synthesis-gas but it is expected that the overall plant effluents and thermal efficiency will be about the same if pure hydrogen is fed to the reactor. However, if the liquefaction process were used only to convert coal to the heaviest liquid while still meeting sulfur regulations, then the hydrogen consumption would be less than the three weight percent on coal used by Parsons, and this could improve the thermal efficiency provided that the balance is such that all of the char or filter cake can be disposed of efficiently.

A number of conventional methods are available to make the hydrogen required in the process from by-product fuel gas, or from liquid products. Another method is to gasify the filter cake which consists of the ash and char not converted in the liquefaction reactor, along with a certain amount of liquid product which is not separated from it. Additional liquid is needed to slurry the filter cake so that it can be handled. The method used by Parsons is to gasify this ash slurry with oxygen and steam in a high temperature slagging gasifier similar to that being developed as part of the BI-GAS process (12). The gasifier operates at about 3,000°F and 200 psig.

Gasification provides one way to dispose of the filter cake and convert it to a clean high-value fuel gas, although there may be no advantage to using this as the source of hydrogen for the liquefaction process. It would seem preferable to burn this low BTU gas in a combined cycle boiler. Then hydrogen for the process would be made by a simple conventional reforming process, feeding the methane and lighter fraction of the fuel gas. If this should contain too much nitrogen or is otherwise difficult to clean up for reforming, then the hydrogen could be made by reforming the light liquid fraction of the product, for example, the C_3 to C_5 cut. There appears to be enough of either one of these streams to provide the hydrogen needed.

3.2 Process Description

The SRC design is based on converting 10,000 tons/day of Illinois type bituminous coal to net liquid products amounting to 25,000 barrels/day of heavy clean liquid fuel, of which 2/3 has a sulfur content of 0.5% while the remaining 1/3 contains about 0.2% sulfur. The plant facilities can be conveniently grouped into several areas including coal preparation and handling, coal liquefaction and filtration, gas cleaning and acid gas removal, product handling and treating, char gasification, hydrogen production, and finally auxiliary facilities such as utilities, oxygen manufacture, water treating, and a sulfur plant.

The process is described in the literature (5-11), and in the block flow diagram Figure 1. It starts with run of mine coal, which is delivered in rail cars, unloaded, and mechanically stacked in a storage pile with 3 days capacity. Coal containing moisture is reclaimed from storage and conveyed to a breaker. Refuse larger than 3 inches in size from the breaker is returned to the mine for disposal. Coal smaller than 3 inches goes to a second storage pile with 8000 tons capacity, which feeds the washing and cleaning operation. Here it is processed through a series of jigs, screens, centrifuges and cyclones, followed by a roll crusher to reduce it in size to 1-1/4 inch or smaller. Refuse from this cleaning operation goes to a settling pond to clean-up the water for reuse.

The cleaned coal is dried, sent to a pulverizer, and ground to pass through a 1/8 inch screen. This stream provides the 10,000 tons per day of coal for liquefaction and is transferred to the slurry tank where it is mixed with 20,000 tons per day of recycled solvent. The resulting slurry is recycled through a system supplying the high pressure feed pumps which deliver slurry to the reactor section at 1,000 psig pressure. The slurry of coal and recycled oil is mixed with makeup synthesis gas and recycle gas containing steam formed by injecting and vaporizing sour water recovered from the products leaving the reactor. This mixture of gas and slurry goes through a pre-heat furnace and then to a reactor which operates at about 840°F and 1,000 psig, with about one hour holding time. Total gas flow to the reactor corresponds to about 45,000 cu. ft. per ton of coal processed. In this particular design, synthesis-gas is used in the reactor rather than pure hydrogen. Carbon monoxide in this gas is shifted to hydrogen in the reactor and, the water needed for this is added in the feed. Conversion of coal is about 91% on a moisture and ash-free basis.

The stream leaving the liquefaction reactor passes to a separator at 840°F from which gas is removed overhead and recycled to the reactor after passing through acid gas removal. Liquid from the bottom of the separator is cooled and recycled in part to the slurry mixing tank where it is used to suspend the coal feed so that it can be pumped to high pressure. This recycle portion does not have to be filtered. The remaining liquid from the separator after the reactor goes to a rotary pre-coat filter where ash and solid particles are removed. Liquid product from the filter contains about 0.5% sulfur and constitutes the main clean liquid product from the process. About one third of it is further processed by catalytic hydro-treating with pure hydrogen to reduce its sulfur content to 0.2%.

The catalytic hydro-treating is severe enough to remove oxygenated compounds such as phenols, and nitrogen compounds. Use is made of this feature in processing the waste water for cleanup. Phenols, etc. are formed during coal liquefaction, and an appreciable part of these remain in the water phase that is separated from the reaction products. These phenols are removed from the waste water by extracting with a clean light oil, which is then recycled through catalytic hydrogenation to destroy phenolic type compounds.

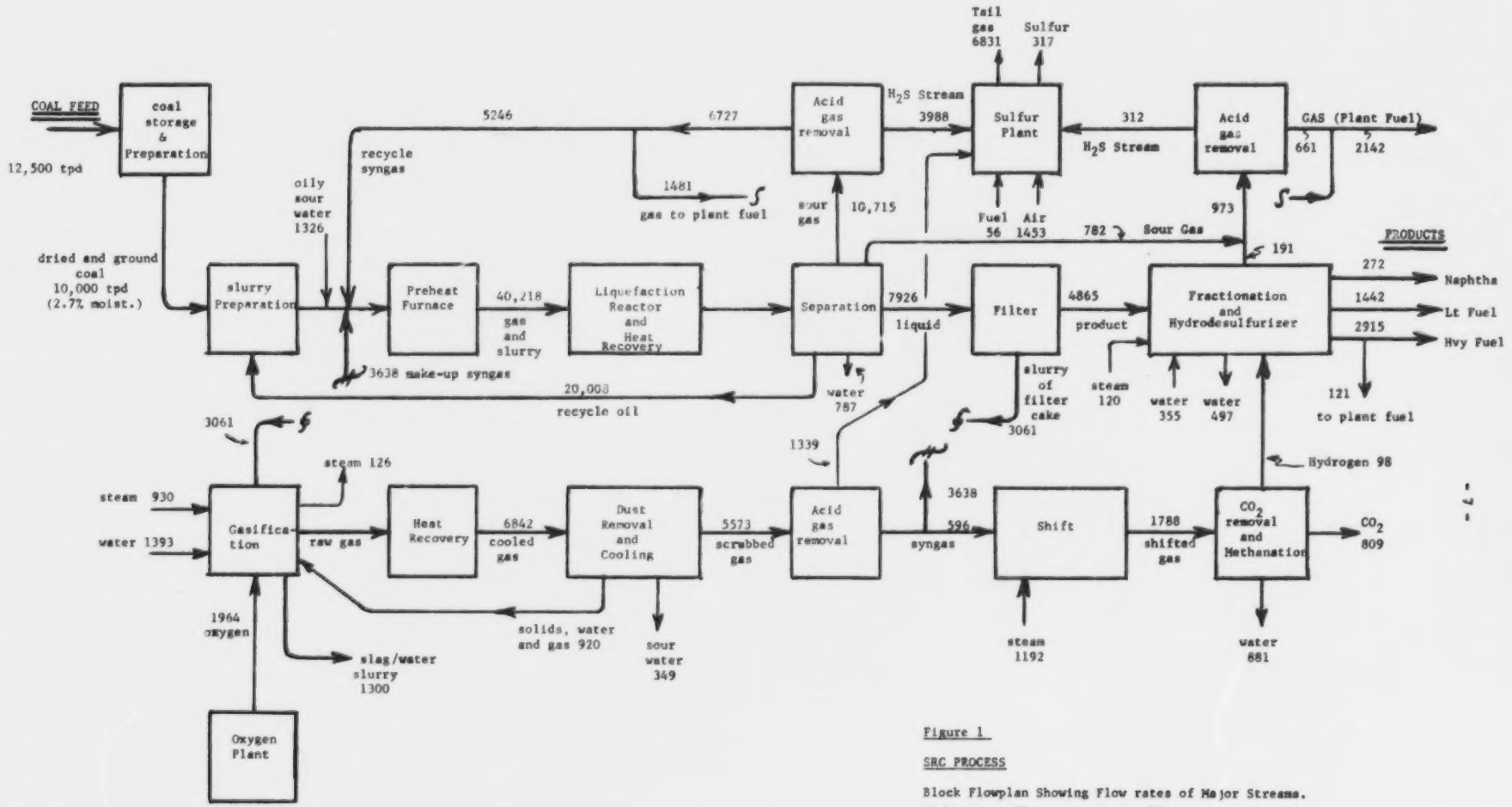


Figure 1

SRC PROCESS

Block Flowplan Showing Flow rates of Major Streams.
Numbers are flow rates in tons/day.

Table 1

SRC Process - Major Inputs to Plant

RAW MATERIALS USED

(1) Run of Mine Illinois No. 6 seam coal:

To gasifier	10,000	tons/day
Fuel to dryer & util.	140	tons/day
	10,140	tons/day

Proximate analysis wt. %

Moisture	2.70*
Ash	7.13
Volatile matter	38.47
Fixed carbon	51.70
Heating value HHV	12,821 Btu/lb

Ultimate analysis wt. %

Carbon	70.75
Hydrogen	4.69
Nitrogen	1.07
Sulfur	3.38
Oxygen	10.28
Ash	7.13
Mositure	2.70*
	100.00

(2) Oxygen, 99.5%, 1964 tons/day

(3) River water, 3626 gpm

---

* After Drying.

Table 2

SRC Process - Major Streams from Plant

NET PRODUCTS

1. 2915 tpd of heavy liquid, with a sulfur content of 0.5%.

Higher heating value	16,660 Btu/lb
API	-9.7

2. 1442 tpd of hydrotreated liquid, with a sulfur content of 0.2%.

Boiling range	400 to 870°F
Higher heating value	18,330 Btu/lb
Gravity	13.9° API

3. 272 tpd of hydrogenated light oils with the following approximate characteristic

Boiling range	C_4 - 400°F
Gravity	52° API
Nitrogen	5 ppm
Sulfur	1 ppm

4. Ash - 713 tpd from gasifier (plus 10 tpd from coal to furnaces)

5. Sulfur of 99.5% purity - 317 tpd

Based on information from other processes, it appears likely that some amines, pyridines, fatty acids etc. will be formed and have to be removed in the clean-up operations. Insufficient data are available at this time to define this situation clearly.

The raffinate, or water layer is stripped to remove light gases, including ammonia and hydrogen sulfide, which are sent to the sulfur plant. Contaminants remaining in the water layer are considered to be low enough so that processing in a biological oxidation system will give adequate clean-up to permit discharging the water effluent to a river for example. A further discussion of considerations in cleaning-up waste water is given in Section 6 of this report.

4. EFFLUENTS TO AIR

4.1 Coal Preparation and Storage

All inputs and effluents are summarized in block flow diagram Figure 2, and described in Tables 3 and 4 according to available data. Environmental aspects are described and evaluated in the following discussion.

The first effluent to the air in the process flow is from the coal storage and preparation area. Coal is received in rail cars or trucks and dumped into a hopper. From there it is moved by conveyors to a storage pile with 3 days capacity, or 37,500 tons. Coal is reclaimed from storage by a bucket wheel and conveyors which move it to the cleaning facilities. A dust nuisance could be generated from the unloading and loading equipment and conveyors, therefore, these should be covered as much as possible to minimize dusting and spills. Good housekeeping is essential since trucks or the wind will pick-up and disperse any dust in the area. Specific clean-up equipment should be provided such as a vacuum system and clean-up trucks, plus water sprays and hoses as needed to flush any dust into the storm sewer system for recovery in the storm pond.

Large coal storage piles often contribute to a dust nuisance, although it may be possible to control this by spraying the pile with liquefied product or asphalt. Spontaneous combustion can occur in coal storage piles and result in evolution of fumes and volatiles. As one control measure, equipment for compacting the pile as it is formed has been indicated and it will also be desirable to monitor the temperatures within it. In any event, plans and facilities should be available for extinguishing fires if they occur (13). For the specific design being considered, only 3 days storage is provided, consequently it should be possible to avoid the problems by simply using storage silos with nitrogen blanketing.

In the washing plant coal is screened, crushed, and a slurry of fine refuse is sent to the tailing pond. The coal washing section is relatively free of dust since it is a wet operation, but spills can occur, and when they dry out can create a dust nuisance. This has been a problem for example on some retention ponds used for disposal of tailings (14).

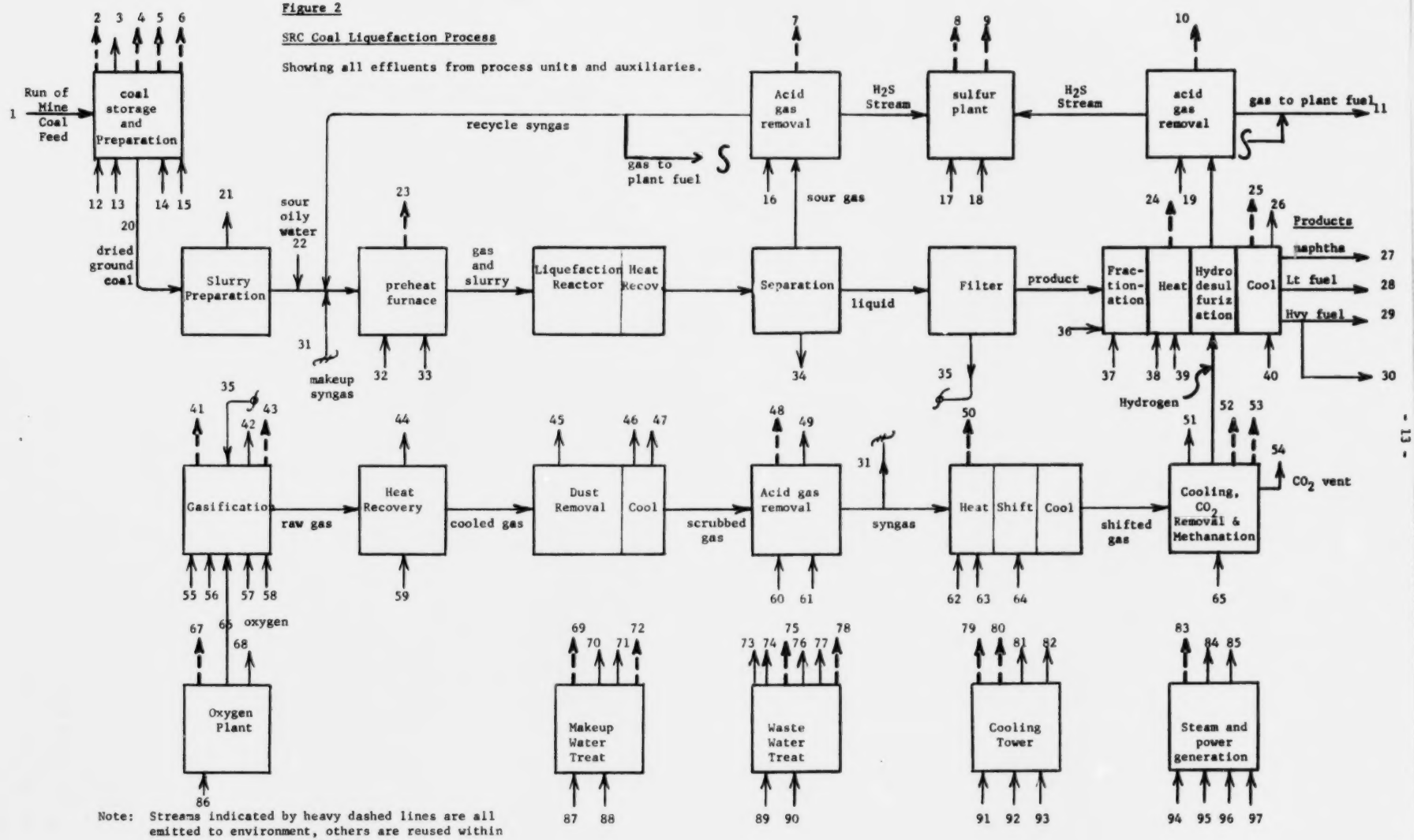
Noise control should be carefully considered since it is often a serious problem in solid handling and size reduction. If the grinding equipment is within a building, the process area may thereby be shielded from undue noise, but additional precautions are needed for personnel inside the building.

The next process step is to dry the washed coal, using a flow dryer to reduce the moisture content to 2.7%. In the design of Ralph M. Parsons, part of the dried coal supplies the fuel required for drying. However, the sulfur content of this coal is very high and flue gas clean-up would be required to remove sulfur as well as particulates. An

Figure 2

SRC Coal Liquefaction Process

Showing all effluents from process units and auxiliaries.



Note: Streams indicated by heavy dashed lines are all emitted to environment, others are reused within the plant or leave as products.

Table 3

SRC Process

Detailed Definition of Streams Including All Effluents from Plant

Stream No.	Identification	Amount lb/hr	Comments
1	Coal feed	1,041,667	ROM coal 12,500 tpd, 10% moist.
* 2	gangue	208,334	separated by screening
3	wash water	1,830,964	used for washing coal, recirculated
* 4	rain runoff	eg 6" rain in 24 hours	from coal storage and handling area
* 5	dryer vent gas	244,311	coal is dried to 2.7% moisture
* 6	dust	eg 10,417	from coal prep. & drying - collected in bag filters
* 7	chemical purge	**	purge soln. from acid gas removal
* 8	sulfur	26,417	by-product sulfur
* 9	tail gas	569,250	treated tail gas from sulfur recovery
* 10	chemical purge	**	purge soln. from acid gas removal
11	gas produced	178,500	C_4 - product to plant fuel
12	rain	eg 6" in 24 hr.	rain onto coal stor. and process area
13	wash water	1,830,964	used to wash coal - recirc., and purge to pond
14	air	122,070	air for combustion to heat dryer
15	fuel to dryer	6,853 2,700	low sulfur gas fuel to dryer (from plant fuel gas); high sulfur coal fines to dryer as limited by sulfur emission
16	makeup chem	**	chemicals for acid gas removal (eg ami
17	air	121,100	air to burner and incin. in sulfur pla
18	fuel gas	4,667	C_4 - fuel to S plant burner and tail gas cleanup (from plant fuel gas)

* These streams are all emitted to the environment.

** See Table 4 for details.

Table 3 (continued)

	19	chemical makeup	**	chem. makeup for acid gas removal
	20	coal to reactor	833,333	dried cleaned coal feed to process (2.7% moist.)
	21	water vapor	23,333	moist. in coal (2.7%) released in hot slurry
	22	oily sour water	110,500	from product recovery
*	23	flue gas	873,180	from furnace preheating slurry to reactors
*	24	flue gas	135,156	from prht. furn. on fractionation to hydrotreating
*	25	air from airfins	6,289,000	airfin cooling alternative to save cooling water
	26	sour water	41,417	water from hydrotreating heavy prod.
	27	naphtha product	22,667	C_5 - 430°F naphtha, 52° API, 5 ppm N, 1 ppm S
	28	light fuel oil	120,167	400-870°F, 13.9° API, 0.2%S, HHV 18,330 Btu/lb
	29	heavy fuel oil	242,917	-9.7° API, 0.5%S, HHV 16.660 Btu/lb
	30	heavy fuel oil to plant fuel	10,083	-9.7° API, 0.5%S, HHV 16.660 Btu/lb
	31	syngas to reactor	303,167 (7.4 MMCFH)	supplies hydrogen for coal conversion
	32	fuel gas	61,650	Reactor preheater furnace 1039.5 MM Btu/hr
	33	air	811,850	Reactor preheater furnace 1039.5 MM Btu/hr
	34	sour water	65,583	Contains ammonia, H_2S, phenols, etc. and is recycled through furnace & reactor
	35	ash slurry to gasif.	255,080	Unreacted coal residue & equal wt. of heavy prod.

* These streams are all emitted to the environment.

** See Table 4 for details.

Table 3 (continued)

	36	steam	10,000	open steam to fractionator
	37	water	29,583	water used to wash oil
	38	fuel gas	9,543	furnaces on fractionation & hydrotreat: 160.9 MM Btu/hr
	39	air	125,663	furnaces on fractionation & hydrotreati 160.9 MM Btu/hr
	40	air	6,289,000	airfin coolers to save cooling water
*	41	slag	108,333	water slurry containing 59,400 lb/hr as
	42	steam	10,500	by product steam from waste heat
*	43	flue gas	35,440	from preheat furnaces on gasifier
	44	h.p. steam	321,000	steam made in waste heat boiler
	45	dust	76,667	dry char recovered & recycled to gasifier
	46	recycle slurry & ga.	44,175	sour water, slurry from scrubber containing 18,900 lb/hr solids is mixed with 6,350 lb/hr of scrubbed gas and recycled to gasifier.
	47	condensate	29,083	sour condensate, returned to liquif. reactor.
*	48	chemical purge	**	chemical purge from acid gas removal and caustic scrubbing on syngas
	49	acid gas	111,583	to sulfur plant from amine scrubbing (11.5 vol. % H_2S)
*	50	flue gas	65,394	from preheat furnaces on shift converte
	51	condensate	71,667	water condensed after shift
*	52	CO_2	67,417	CO_2 rejected to air from Benfield unit after shift
*	53	chemical purge	27,168	net discharge of waste water from Benfield CO_2 removal unit, may contain some carbonate

* These streams are all emitted to the environment.

** See Table 4 for details.

Table 3 (continued)

54	condensate	1,750	water condensed after methanation
55	steam	77,500	steam to gasifier
56	water	116,083	water added to quench slag
57	plant fuel gas	2,440	to preheat furnaces on gasifier
58	air	33,000	air to preheat furnaces on gasifier
59	water	321,000	boiler feed water to waste heat boiler.
60	air and condensate	--	to back flush filters on circulating amine. Gas is vented to S plant and liquid goes to waste water treating.
61	chemical makeup	**	makeup to acid gas removal - amine, additives, sodium hydroxide
62	plant fuel gas	4,620	to preheat furnace for shift converter
63	air	60,800	to preheat furnace for shift converter
64	boiler feed water	99,333	to make steam fed to shift converter
65	chem. makeup	**	makeup chemicals to Benfield unit
66	Oxygen	163,700	oxygen to gasifier (99.5%)
* 67	Nitrogen	616,300	vented from oxygen plant
68	condensate	4,500	moisture from air, typical
* 69	sludge	**	from treating makeup water with lime, alum
70	boiler feed water	213,738	to steam generation
71	cooling water	1,328,378	makeup to cooling tower
* 72	backwash	**	acid, caustic, used to regenerate
73	phenols, etc.	--	extracted & returned to hydro unit to destroy it. But it could be recovered & sold as a by-product
74	H_2S	--	from final stripping, sent to sulfur plant.

* These streams are all emitted to the environment.

** See Table 4 for details.

Table 3 (continued)

* 75	water	532,193	treated waste water leaving plant
76	ammonia	est 4,000	formed from nitrogen in coal
77	oil	--	from API oil separator on waste water treating. (add to oil product)
* 78	sludge	--	from biox unit on waste water - to be dewatered & incinerated
* 79	air	670,000,000 (31 MMM SCFD)	air from cooling tower
* 80	drift loss	est 100,000	water mist lost in air
81	blowdown	301,555	water purge from cooling tower
82	cooling water	60,634,000	recirculated cooling water
* 83	flue gas	1,246,560	from utility boiler & turbine/gener.
84	blowdown	61,123	water purge from steam gener.
85	steam	242,331	generated in utility boiler
86	air	780,000	to supply oxygen plant
87	chemicals	**	for water treating, lime, alum, etc
88	water	1,813,208	raw makeup water
89	additives	**	used to treat waste water, recover phenol, oil, etc.
90	waste water	532,193	processed water from separators(include 19,606 lb/hr sour water which is part o the waste water balance shown on p. 68)
91	chemicals	**	additives to cooling water
92	air	670,000,000 (31 MMM SCFD)	air to cooling tower
93	water	60,634,000	water recirc. to cooling tower
94	plant fuel gas	78,000	fuel to steam & power gener.

* These streams are all emitted to the environment.

** See Table 4 for details.

Table 3 (continued)

95	SRC heavy liq. prod.	10,083	supplemental fuel for utility boiler
96	air	1,159,00	combustion air to boiler plus gas turbine/generator.
97	boiler feed water	213,738	for steam generation - util. boiler

Footnote: ** For details on chemicals consumed, see Table 4.

Table 4

SRC Process

Catalyst and Chemicals Consumption

(as indicated in report by Ralph M. Parsons)(11)

Catalyst or Chemical	Basis or Makeup Requirement
Diatomaceous Earth Filter Precoat	20 tons/day
Monoethanolamine (1)	1750 to 7000 lb/day
Cellulose, Asbestos, and Diatomaceous Earth (1)	20 to 100 lb/day
Corrosion Inhibitor (1)	2 to 4 gal/day
Antifoam (1)	5 to 10 gal/day
Hydrogenation Catalyst	253,000 lb (3-yr life)
Hydrogenation Catalyst	2,700 lb (3-yr life)
Monoethanolamine (2)	500 lb/day
Cellulose, Asbestos, and Diatomaceous Earth (2)	2 to 10 lb/day
Corrosion Inhibitor (2)	1/4 to 1/2 gal/day
Antifoam (2)	1/2 to 1 gal/day
Monoethanolamine (3)	1500 to 5100 lb/day
Sodium Hydroxide* (3)	340 lb/day *
Active Carbon (3)	50 to 100 lb/day
Corrosion Inhibitor (3)	1 to 2 gal/day
Antifoam (3)	2 to 5 gal/day
CO Shift Catalyst	2399 ft^3 (1-yr life)
Benfield Solution - K_2CO_3	986 lb/month
DEA	99 lb/month
V_2O_5	17 lb/month

(1) Dissolver acid gas removal.
(2) Fuel gas sulfur removal.
(3) Gasifier and gas removal.

* Does not allow for significant consumption in sulfur cleanup from gasification section, which could increase consumption by more than 10 fold if all carbonyl sulfide is removed by reacting with sodium hydroxide

Table 4 (continued)

Catalyst or Chemical	Basis or Makeup Requirement
Methanator Catalyst	140 ft^3 (3-yr life)
Zinc Oxide Pellets	71 ft^3 (3-yr life)
BSRP CoMo Catalyst	750 ft^3 (3-yr life)
Sulfur Recovery Catalyst	5200 ft^3 (3-yr life)
Stretford Solution Chemical Makeup	$386/day
Corrosion Inhibitor	319 lb/day
Polymer Dispersant	319 lb/day
Sulfuric Acid	3209 lb/day
Chlorine	1766 lb/day
Phosphate Polymer Antifoam	383 lb/day
Hydrazine	2.7 lb/day
Lime	2072 lb/day
Aluminum Sulfate	1295 lb/day
Caustic Soda	2135 lb/day

alternative is to burn part of the product gas as fuel in the dryer and use bag filters or a water scrubber to control particulates. While Parsons did not show the volume of flue gas leaving the dryer, their fuel consumption is high, which may reflect a large excess of air. This fuel consumption can be reduced more than 50% by using a minimum amount of excess air and allowing a higher moisture content in the flue gas. At the same time, the volume of vent gas to clean-up is similarly reduced.

4.2 Liquefaction and Filtration

Dried coal is pulverized to 1/8" and smaller and fed to the liquefaction section at a rate of 416 tph. Again, control of dust and noise is required for the handling operations.

The coal is mixed with twice its weight of recycle oil at 550°F, to form a slurry at 368°F that is pumped to high pressure. Upon mixing, moisture in the coal evaporates, is recovered in a condenser, and is returned to the slurry, so that this water does not become an effluent from the plant.

The slurry is mixed with recycle gas plus make-up synthesis gas and fed to a pre-heat furnace where it is heated to 900°F. Operability and erosion on this furnace, feeding a mixture of tar slurry and gas, is considered to be a problem. Leaks or burn out of tubes could result in serious emissions to the atmosphere. The furnace has a very large heat-load and is fired with part of the product gas, generating 305 million cubic feet a day of flue gas. Clean fuel is fired, and therefore sulfur or particulates should not be a problem. A target value for nitrogen oxides is 0.2 lbs per million Btu's, as required on large stationary boilers (15). It should be possible to meet this value by careful control of combustion conditions in the furnace, possibly with staged firing of fuel (16). Emission of nitrogen oxides needs to be estimated in any actual application of the process.

Hydrogen is formed in the reactor by water-gas shift, consequently considerable steam must be added to the reactor. This steam is supplied by evaporating water recovered from the process which is thus reused and does not become an effluent from the plant. This water may contain some particulates and traces of oil. Fouling and corrosion of exchangers used to evaporate such sour water streams can be a major concern even if no particulates are present. In the Parsons design, this process water is mixed with recycle gas and evaporated to dryness by exchange with hot vapors from the reactor. This operation may involve periodic depressuring for cleaning and special techniques calling for careful consideration of environmental impact.

In general, this section of the plant is completely enclosed and no streams are normally discharged to the atmosphere from the reactor and filtering sections. However, the reactor operates at 1,000 psig, so that any leaks on pumps, valves or other equipment can result in serious pollution problems. For example, the air-fin coolers used on the gas and liquid products have fans to move a very large volume of air over the exchangers, and it is apparent that any leakage will be dispersed in this large air stream. Further consideration of this problem is needed to assure that the plant operations will be environmentally satisfactory (17).

Indirect heat exchange versus recirculated cooling water is used in the high pressure reaction section as well as in other parts of the plant. It is common to find a small amount of leakage on conventional exchangers in this type of service, particularly at high pressures such as 1000 psig. Materials that leak into the cooling water can circulate to the cooling tower where they will be stripped out by the large volume of air passing through the tower. Special attention to this problem has been given in the case of oil refineries and this experience should be reviewed and applied in coal conversion operations (17).

Maintenance, depressuring, and purging of equipment will call for special attention to control emissions. A special collection system should be used to contain and clean up all purge and vent gas streams.

In the filtration section, slurry from the reactor passes through pressure rotary filters to remove ash and residue from the oil product. Again, the system is enclosed but is complicated due to the operation of multiple units, pre-coating of filters, gas purge, and re-slurrying of filter cake. Thorough consideration in the design is needed with regard to potential leaks, spills, and pressure venting and shutdown and servicing. A separate low pressure gas collection system may be needed for purge from this area so that it can be scrubbed and reused, or burned in one of the furnaces.

Pneumatic transport is provided on the filter aid used as precoat. Such systems can create a dust nuisance and efficient control measures should be employed, such as bag filters at sub-atmospheric pressure.

4.3 Product Handling and Hydrotreating

The primary product stream of filtered reactor liquid is fractionated to give naphtha and a light distillate, both of which are further hydrotreated. Heat for distillation is provided by a furnace which generates a significant amount of flue gas. Since product gas is used as fuel, it should be practical to meet the emissions requirement for large stationary boilers with regard to sulfur, particulates, NO_x, and CO (16).

The product hydrotreating section also uses furnaces for pre-heating before the reactor and on stripping the product. The comment made on the distillation furnace applies here also. Hydrogen compression is included in this section, and since it involves high pressure, the possibility of leaks requires special consideration as discussed previously.

When the high pressure liquid products are depressured, a considerable amount of dissolved gas is released, which should be recovered or used for fuel. Similarly, when the sour water is depressured, gas will be released which would cause a serious odor problem if vented to the air. Facilities are, therefore, needed to recover this gas and send it to the sulfur plant.

When maintenance is needed on the high pressure facilities they must first be depressured, and provisions should be made for recovering materials released during the depressuring. In addition, the equipment must be purged with inert gas, and again, recovery facilities should be provided to avoid undesirable emissions to the atmosphere at such times. A more detailed discussion is given in Reference (2).

4.4 Acid Gas Removal and Hydrogen Manufacture

Separate acid gas removal units are provided on: the gas recycled to the reactor, product fuel gas, after the gasifier, and in hydrogen manufacture. Amine scrubbing is used to remove sulfur from the recycle gas to aid desulfurization, and on the product gas so as to provide clean fuel for use in the plant. Scrubbing removes H_2S which goes to a sulfur plant. It is expected that there will be other forms of sulfur present such as carbonyl sulfide which will not be removed effectively by amine scrubbing. This is particularly true for the gasification system supplying raw gas for hydrogen manufacture since the high CO content of the gas results in a high formation of COS, as much as 10% of the total sulfur content in some similar systems (1). This will be removed by caustic scrubbing in the Ralph M. Parsons design but creates a very large amount of spent caustic that needs disposal. Some work has been reported on hydrolyzing COS etc. to H_2S over catalyst, prior to amine scrubbing (18), which would improve the situation. Scrubbing the raw gas with hot carbonate may be preferrable, as it should remove COS without consuming caustic. Perhaps a better alternative is to use the low Btu gas from gasification as plant fuel where the clean-up requirements are less stringent, and then make hydrogen from product gas using well demonstrated technology.

Trace components such as cyanides can react with amine to form stable compounds which must be purged from the system. These can present a disposal problem, although they can be incinerated. Also, some solid materials are removed from the circulating amine liquid and the design includes rather large filters for this purpose. The exact nature and amount of these solids should be accurately determined so that proper provision can be made for their disposal, and for control of atmospheric contamination from odors, vapors and dust. The design shows vents to the atmosphere from amine storage, the amine purge tank, and the amine sump. These systems are blanketed with inert gas, and all such vent streams should be collected and properly handled, for example, by passing to an incinerator or furnace for destruction.

In the section making pure hydrogen for hydrotreating, all CO in the feed gas is shifted with steam and the CO_2 scrubbed out using the proprietary Benfield hot carbonate process (19). This makes a concentrated CO_2 stream which is vented to the atmosphere (809 tpd CO_2), and assurance is needed that it is low enough in sulfur, mist, and chemicals, etc., to be acceptable, and that it is vented in a way to avoid hazards. One concern is that various sulfur and other compounds from gasification may be removed along with CO_2 and contaminate the CO_2 vent stream. Additional facilities may be required to clean up this stream, and we have added a scrubbing system for this purpose to recover sulfur compounds. These compounds are then combined with the feed to the Claus plant for processing. Moisture in this gas may cause a plume, which may be acceptable but should be evaluated (1).

The other effluents to the air from hydrogen manufacture are flue gases from three furnaces supplying steam and sensible heat for the hot shift reactors. Since fuel gas is fired, it should be possible to meet target emissions, as discussed earlier in the section on Product Handling and Hydrotreating.

4.5 Gasification and Slag Disposal

In this section the filter cake, mixed with twice its weight of oil to facilitate handling, is gasified with oxygen and steam to make low Btu synthesis gas. The gasifier operates at 1700°F in the top zone, 3000°F in the bottom zone, and 200 psig. It is a modification of a system under development known as BI-GAS. Molten slag is removed at the bottom and quenched to form steam which is returned to the gasifier, while excess water forms a slurry with the fragmented slag so that it can be withdrawn.

Of the oil-filter cake slurry charged to gasification, 30% of it goes to a top zone where the temperature is 1700°F. Consequently, small amounts of tar or oil and soot may be present, in which case additional recovery facilities may be required due to problems with exchanger fouling, emulsion, etc. The design does provide a cyclone to recover dry char from the raw gas and recycle it to the 3000°F zone, since the cake is not completely gasified in one pass. A venturi scrubber is included for final dust removal.

The main effluents to the air from this section are from two furnaces preheating the feed streams to gasification. These furnaces fire clean gas so that there should be no problem in meeting target emissions, as discussed in the section on Product Handling and Hydrotreating. One furnace preheats clean steam to 1050°F for feeding to the top of the gasifier along with 30% of the slurry feed.

The other furnace heats recycle char suspended in gas and steam, for feeding to the 3000°F zone along with the other 70% of the slurry feed. This furnace is subject to erosion and possible plugging due to the presence of solids. Tube failure, or maintenance and cleaning could cause serious emissions which need further consideration with regard to environmental impact.

Sour water from scrubbing the raw gas contains sulfur compounds, ammonia, phenols, etc. This stream is treated before discharge to extract phenols, and goes to a sour water stripper which removes light gases that are sent to the sulfur plant. It then flows through oil separators and to a biox pond. This operation is enclosed and should be satisfactory with regard to odors and air pollution, except that the oily water separator should be covered.

The slag quenching operation is described in general terms, and the 3000°F gasifier zone is segregated from the water slurry, quenching zone. No specific facilities are shown for particle size control, such as grinding, and the system depends on the shattering effect of quenching to form a pumpable slurry.

The design provides a slag storage pile in the coal storage area, prior to back-hauling it to the mine. Since the slag is removed as a slurry, it will have to be drained and stacked. Some of the slag may be very fine, consequently there could be dust problems when it dries out. The extent of odors and sulfur emissions in this operation needs to be determined. Also, water from draining must be recovered and reused, since it will contain considerable suspended solids. It can be recirculated through the storm pond, provided this does not cause secondary pollution problems due to odors or leachable materials.

On the basis shown there should be no streams released to the air from the process equipment on slag handling, since the steam from quenching is returned to the gasifier, and the slag is handled as a slurry. However, the possibility of secondary pollution must be clarified. Dusting has been mentioned, and there could be release of sulfur and odors since the slag is formed under reducing conditions. Studies on the chemistry of the calcium-sulfur systems have been made in connection with controlling sulfur pollution on coal fuel (20). In some cases the spent ash has been reacted with CO_2 and water to remove sulfur before the ash is disposed of (4), and this may provide one way to control secondary pollution.

4.6 Auxiliary Facilities

In addition to the main process, various auxiliary facilities are needed, such as the oxygen plant, sulfur plant, utilities, water treating, and product storage, which must be considered from the standpoint of effluents to the air. The oxygen plant is relatively clean and the only major effluent is rejected nitrogen which can be used for purging, in which case clean-up of the purge gas should be provided. The oxygen plant is a large consumer of power and therefore has an important effect on thermal efficiency and energy consumption. One approach uses electric drives on the main air compressor, but where clean fuel is available a flue gas turbine may be more attractive. Or a high pressure bleeder steam turbine can be used, for example generating steam at 600 psig or higher and depressuring it through the turbine to say 125 psig to supply steam for reboilers on acid gas removal, preheating, etc. When a specific plant design is made, it will be important to optimize the utilities system.

The sulfur plant uses a Claus unit, with tail gas clean-up. Concentration of H_2S in the feed is only 7.7 mole percent, resulting in a low sulfur recovery on the Claus unit. Therefore an efficient tail gas clean-up system is needed and there are a number of available processes to choose from. The design is based on using the proprietary Beavon process to reduce residual sulfur compounds to H_2S, which is then removed in a Stretford type scrubbing operation (21). Other systems could be used for tail gas clean-up such as the IFP, Takahax, Wellman-Lord or Scot processes (22). Vent gas from the tail gas clean-up operation can be vented to the atmosphere without incineration in some cases.

The Stretford type process uses a scrubbing liquid containing catalyst to oxidize H_2S to free sulfur (23). The scrubbing liquid is then reoxidized by blowing with air, and precautions must be taken to avoid release of odors or entrained liquid etc. to the atmosphere. This air effluent should pass through an incinerator or furnace unless it is clear that H_2S and other emissions will be acceptable.

Product sulfur may be handled and stored as a liquid in completely enclosed equipment to avoid emissions. If it is handled and stored as a solid, control of dusting will be required.

Several factors tend to reduce efficiency of a Claus plant, including the presence of combustibles such as ammonia or hydrocarbons in the feed, which require additional air for combustion. Carbon dioxide or water vapor act as diluents, with a corresponding increase in volume of tail gas from the Claus section. The effect of inerts is illustrated by the following table which shows the relationship between % H_2S in the feed gas, and tail gas volume relative to feeding 100% H_2S.

% H_2S in Feed	Relative Gas Vol.
100	1
25	2
15	3
10	4
8	5

Higher gas volume means that more tail gas must be cleaned up to a lower residual sulfur content, for the same T/D sulfur to the air. Moreover, at low % H_2S, extraneous fuel may have to be fired in order to hold the needed temperature in the 1st stage burner, further contributing to inefficiencies.

High CO_2 in the feed can significantly increase formation of COS and CS_2, while ammonia contributes to NO_x formation (24). Techniques are available for removing these gases to give a higher concentration of H_2S to the sulfur plant, but the desirability of doing so will depend on the particular situation and should be evaluated.

The largest volume of discharge to the atmosphere from the utility area is on the cooling tower. Air flow through it is about 31,000 MM cfd, and it is therefore critical from the standpoint of pollutants. It might be expected that the recirculated cooling water would be perfectly clean and free of contaminants, however, experience shows that there will be appreciable leakage in exchangers and occasionally tube failures, especially with high pressure operations. In the present design cooling water is exchanged with oil, sour water, raw gas, amines, etc.; therefore, contaminants may get into the circulating cooling water and then be transferred to the air in the cooling tower, which necessarily provides effective contacting and stripping.

In oil refining and petrochemical operations, the cooling tower is often a major source of emissions from the plant, and techniques have been developed for making quantitative estimates of the loss (17). Control measures are also described, with emphasis on good maintenance on valves, pump seals, etc., plus floating roof tanks or vapor recovery as needed. In critical cases monitoring instruments should be used to detect leaks.

Cooling towers also have a potential problem due to drift loss, that is mist or spray which is carried out with the effluent air. Since this contains dissolved solids it can result in deposits when the mist settles and evaporates. In addition there is a potential plume or fog problem, if the atmospheric conditions are such that moisture in the air leaving the cooling tower condenses upon mixing with cooler ambient air. This occurs whenever the mix temperature is below that corresponding to saturation. Although reheating the effluent air will prevent the plume, it is not normally warranted and consumes energy unless it can be accomplished using waste heat.

The utilities section includes a boiler to provide steam and electric power. It has a large gas effluent, so that emissions of dust, sulfur, NO_x and CO must be controlled. The large fuel consumption of the boiler has a correspondingly large effect on thermal efficiency of the overall plant.

Dust emission can be controlled with demonstrated conventional equipment such as cyclones, electrostatic precipitators, or scrubbers. Sulfur can be removed as required, by one of the many processes offered for this use (31,32,33). Processes are available from the following:

Wellman-Lord	Chiyoda	FMC Corp.
Chemico	Showa Denko	Mitsui S.P. Inc.
Combustion Engineering	Babcock & Wilcox	Davy Power Gas
Universal Oil Products	Lurgi	Stauffer Chemical Co.
Research Cottrell	Enviro Chem. Systems	

Some of these are commercially demonstrated and others are undergoing large scale tests.

NO_x may be decreased by controlling the combustion conditions and by staged firing (16). Even so it may be difficult in some cases to meet the target emissions set for large stationary boilers. Considerable work is under way on methods to remove NO_x from the flue gas. While NO_2 is relatively easy to scrub out, it is found that most of the NO_x is in the form of NO which is very difficult to remove due to its low solubility in water. One answer is to convert NO to NO_2 which can then be scrubbed out, but a simple, efficient way to accomplish this is not yet available. Other approaches are to effect chemical reactions with NO_x to decompose it to free nitrogen gas. The problem is receiving intensive effort and it is expected that at least one demonstrated process will be available in the near future for use on utility boilers.

Thermal efficiency of any coal conversion process must take into account the fuel consumed in utilities generation, since this can amount to 15-25% of the main process. In general it is desirable to burn low grade fuel such as char or coal rather than high value product gas or liquid. In the case of the SRC process its purpose is to produce clean boiler fuel so that it is reasonable to use this product to supply utilities fuel, as required. It is important to achieve high efficiency in generating utilities and the combined cycle is, therefore, receiving a lot of attention. In the combined cycle, a gas or liquid fuel is burned at perhaps 10 atmospheres pressure, giving hot gases which are passed through a turbine to generate electric power and then to a boiler generating high pressure steam. Solid fuel, such as coal, can also be used by gasifying the coal and cleaning up the raw gas to provide low Btu gas fuel for the turbine. Such alternatives need to be evaluated carefully in each specific application in order to define the best combination.

Sour water from liquefaction contains compounds with strong odors, such as phenols, H_2S, and ammonia. In the waste water treating section, phenols, etc. are extracted from the sour water by contacting it with a light oil, which is then recycled through catalytic hydrogenation to destroy compounds containing oxygen or nitrogen. The raffinate is then stripped to remove H_2S, ammonia, and traces of oil and solvent which are disposed of to the sulfur plant. Ammonia might be recovered as a by-product, as has been described in the literature (25). However, most of the nitrogen in the coal remains in the oil product and, therefore, the production of ammonia is small.

Depending upon the efficiency of the extraction and stripping operations, the level of contaminants in the waste water may be reduced to a level low enough to be acceptable without over-loading the biox unit. An oil separator is provided ahead of the biox. Except for this and the biox unit, these facilities are all enclosed in order to avoid any direct effluents to the atmosphere. Sour water from the gasification and product hydrotreating areas is also stripped to remove H_2S and ammonia prior to discharging to the biox unit.

In view of the very strong odor created by phenols and by components in the sour water, careful consideration should be given to this in planning and designing all plant facilities. All oil-water separators should be covered to contain odors, and it is possible that the biox unit will also need to be covered. Further experimental data should be obtained to define the requirements for this. The SRC oil product contains various oxygenated compounds, including phenols and cresols, as well as relatively large amounts of nitrogen compounds such as pyridine types. These have very strong odors and can create problems in handling and storage.

If the product is solidified by cooling in a prilling tower with direct contact with air, obnoxious fumes can be formed (similar to those generated in asphalt oxidation). These cannot be discharged to the atmosphere and might be incinerated, or gas recirculation could be used with indirect cooling. An alternative is to solidify the product on a metal belt which is cooled by exchange with water. Instead of making a solid product, it could be kept hot above the melting point and handled as a liquid, in which case it will be important to exclude air from the storage and handling facilities. Tests on similar type materials have shown that oxidation reactions induce polymerization, resulting in a large increase in viscosity, and potential gum and asphaltic deposits (26). Storage tanks are needed with inert gas purge which is vented to the incinerator to control emissions and odors.

5. EFFLUENTS - LIQUID AND SOLID

5.1 Coal Preparation

Large size coal is brought from the mines by rail or truck and passed through a breaker to reduce it to 3 inches and smaller. Oversize refuse from this operation is returned to the mine, while the coal is stored in a pile having 3 days capacity. In all of the storage and handling area consideration must be given to the problems of spills and contamination due to rain run-off. This water can become acidic due to reaction for example with pyrite. There is also the possibility of extracting organics or soluble metals from the coal or gangue. Therefore, this run-off water should be collected and sent to a storm pond, separate from that for the process area so that oil contamination is minimized. This pond should have a long enough residence time for solids to settle out and there should be a certain amount of biological action which will be effective in reducing contaminants. It may be desirable to add some limestone to this circuit if needed to correct acidity. The problem is somewhat similar to acid mine water and should be reviewed from this standpoint (27).

Water from this retention pond will be relatively clean and low in dissolved solids and therefore is a good make-up water for the plant cooling tower circuit and for preparation of boiler feed water. Where all of the run-off can be used in this way, it will not constitute an effluent from the plant.

Leakage or leaching from this storm pond must also be considered. Normally, this should not be a serious problem but in some cases overflow from retention ponds in heavy storms has contributed to stream pollution. Seepage through the bottom of the pond into the ground water must also be controlled. In some comparable situations, seepage down through a process area can be a problem in addition to the runoff. Even though storm sewers collect the runoff in a chemical plant or oil refinery, leaks and oil spills can release enough material such that it actually seeps down into the ground water supply. If the ground contains a lot of clay this will not usually be a problem - in fact the clay can absorb large quantities of metallic ions. In sandy soil it may be necessary to provide a barrier layer underneath the coal storage piles. This could be concrete, plastic or possibly a clay layer. Storm sewers from the process area should also be collected and sent to the pond. In the present design this may be satisfactory, but if there is a likelihood of serious spills of oil or phenols, the process area should be drained to a separate holding pond for treatment.

In the washing and screening system, the coal is handled as a slurry with the water recirculated, so there should be no net effluent from this operation. The recirculated water passes through a thickener, the over flow from which provides the recirculating wash water. Bottoms from the thickener go to a tailing pond where particles smaller than 1 mm are removed by settling, so that the water can be recirculated and reused.

Some suitable provision will have to be made to dispose of the large amount of waste solids rejected from the coal cleaning operation. The overall balance shows 2500 tpd of this material. To the extent that this is coarse material it should not present a serious dusting problem, however, the pyrites content can be expected to oxidize and subsequently be leached out, resulting in possible contamination of natural water with acid, iron, or other materials. Rejected fine solids, 1 mm and smaller, accumulate in the tailing pond. The sheer magnitude of this stream poses a major problem which calls for very careful and thorough planning. The fines amount to 52 tph of solids. To put this in perspective, if the tailing pond has a surface area of 1 acre and the fine solids are at 100 lbs per cubic foot, then the sediment will build up at a rate of 180 feet per year. Obviously, this material will have to be reclaimed from the tailing pond and disposed of off-site. Perhaps it can be used as land fill provided leaching is not a problem, but the material is very fine and if it dries out it may constitute a dust nuisance. Land reclaimation studies have been made on similar materials and these should be studied thoroughly in planning disposition of refuse from coal cleaning operations. (14)

The next solid effluent is from coal drying, where the ground coal is suspended in a large volume of gas. Dust must be recovered efficiently and a target is 0.1 lbs of particulates emission per MM Btu fired for large stationary boilers. For dust removal bag filters, water scrubbing, or electrostatic precipitation might be used. The recovered coal fines could be used in the process, or as fuel, to the extent sulfur emissions are acceptable; in which case, dry recovery would seem to be advantageous. An alternative is to slurry the fines in water and feed them to the liquefaction reactor. Moisture in the coal evaporates in the slurry mixing tank and this water vapor is then condensed and returned to the reactor, therefore it provides a convenient stream to use for slurrying fines returned to liquefaction.

5.2 Liquefaction and Filtration

The large volume effluents in this section are from the furnaces and air fin exchangers. While these have a large impact on the air emissions, they should not contribute substantially to the water or solids effluents. There is considerable handling of coal slurry, and, in addition, the precoat used in filtration requires storage and handling. All of these operations are enclosed so that normally they will not generate undesirable effluents. The process operates at high pressure and therefore leaks on valves, pump seals, etc. can be expected, and will cause pollution problems unless adequate plans and provisions are included in the project planning.

For example, leaks in the process area will cause odors due to the cresols and other minor components in the liquefied coal. Experience shows that even a severely hydrotreated oil from similar operations still retains a distinctive odor of cresols. Oil leakage will be washed off

by the rain and can get into the ground water or streams possibly causing a very undesirable taste. Therefore, drainage from the process area should be collected in separate sewers for special handling. Oil separation on the water is needed, for example by API type separators as used in oil refining, and possibly froth floatation, and activated carbon for odor control. The effluent can then be discharged to a holding pond and further treated as required to make it suitable for reuse as make-up water.

Sour water is separated from the reactor effluent by settling, and, in the design, it is recycled to the reactor after mixing with the coal slurry ahead of the preheat furnace. To the extent that this is practical without undue corrosion and fouling, it affords a very desirable disposition of sour water. If an alternative use is needed because of operating problems, it may be necessary to add a sour water stripper. As this is a large stream, such a sour water stripper would result in additional fuel consumption.

The filtration step is an area of potential leaks and spills in that it is complicated, involves solids handling, and operates at elevated temperature and pressure on a heavy viscous oil. Also the filter cake is scraped off and then reslurried with oil for transfer to gasification. During normal operation there should be no intentional effluents from this system since it is totally enclosed, but a question arises with regard to start-up, shut-down, maintainence, and upsets. No doubt there will be times when the filter cake must be temporarily stored and later worked back into the process, so careful planning is needed in this area. No mixing system is indicated for reslurrying the filter cake, and presumably a mechanical system will be used.

For the specific design there are no major liquid or solid effluents from the liquefaction and filtration sections. The system is enclosed and all of the streams flow to other sections of the process. However, it should be noted that if the sour water from the reaction should become an effluent, rather than being recycled and reused, then the clean-up of this waste water stream would call for a great deal of study. Some aspects to consider are discussed in Section 6.

Complications may result due to release of trace elements during the liquefaction reaction. A few of these such as titanium tend to stay with the oil, while heavy metals such as chromium would be expected to stay with the ash, along with alumina, calcium, and silica. There are also probably a number of trace elements that are released in volatile or water soluble forms, including arsenic, antimony, cadimum, zinc, selenium, fluorine, etc. What ultimately happens to these in the process is not clear at this time. Some of them may show up in the sour water, all of which is recycled to extinction in the reactor, in which case they will build up in concentration in the circulating sour water and have to be separated and purged from the system, and then disposed of in some environmentally sound manner. If volatile compounds are formed such as arsine and metal carbonyls, they will show up in the gas stream and have to be removed. In addition to trace elements, compounds such as cyanides and thiocyanates may form and tend to build-up in the recycle streams. Possibly they will be converted in the reactor to reach an equilibrium concentration - if not, then purging may be necessary.

5.3 Product Handling and Hydrotreating

The major effluents in this area are to the air from furnaces and air fin exchangers, but there is also a significant production of sour water. This is associated with hydrotreating part of the heavy SRC product to lower its sulfur content, which produces H_2S as well as ammonia. Water is injected and mixed with the oil to absorb these contaminants. Production of sour water is about 32,000 lbs per hour and it contains about 1.5% each of ammonia and H_2S. Some of the combined oxygen in the oil is also removed as water.

The sour water stream must be cleaned up in the waste water treating section. In addition to ammonia and H_2S this sour water will contain oxygenated compounds such as phenols as well as traces of oil, cyanides, etc. Hydrotreating of the naphtha product also produces a sour water stream which is similar but smaller in volume and can be combined for waste water treating. (See Section 6.)

Acid gas removal is used on the liquefaction reactor recycle gas stream, on the product fuel gas, and in the gasification-hydrogen manufacture section. Amine scrubbing is used in each of these. Some purge of the amine solution will be needed because of the presence of contaminants which form stable products, but additional data are needed in order to define the amount. The purge can be disposed of by incinerating in one of the furnaces unless some other suitable disposal is defined.

The design includes filters on the recirculating amine solution. The nature of the solid removed by the filter is not specified, but if it is residual ash from the coal then it may be possible to simply include it in the slurry fed to gasification. Definition of the amount, composition, and disposition of this material is needed.

In hydrotreating with pure hydrogen at high pressure most of the sulfur removed will be in the form of H_2S, which can be separated effectively with amine. Since in this particular design the liquefaction reactor operates on synthesis gas rather than pure hydrogen, a considerable amount of carbonyl sulfide will also be formed. Amine is not effective for removing carbonyl sulfide, therefore, it would appear that additional scrubbing is needed in order to remove it. Hot carbonate scrubbing may be satisfactory, or perhaps the carbonyl sulfide could he hydrolyzed to H_2S over a catalyst prior to amine scrubbing. (18) Since it is expected that pure hydrogen will be used rather than synthesis gas, this problem can be avoided.

The hydro-treated products will be liquid and can be stored and sold as such. In liquid storage tanks, some ash may accumulate on the bottom and have to be removed periodically. Perhaps this can be processed along with the filter cake. The gas product is all used as plant fuel and should not cause pollution. The heavy SRC product will be solid at room temperature and may be handled in this form, or it may be melted by heating. It does contain some residual ash and when burned most of this will appear in the flue gas. In order to meet the target for particulate emissions from stationary power plants of 0.1 lbs per MM Btu, the ash content of this product should be less than 0.15%. The reported value of 0.1% ash should be satisfactory, provided the level of trace elements is acceptable.

In addition to the primary products from the process there will be by-products such as sulfur. This can be stored and handled using well established techniques to avoid pollution problems. There is also some ammonia formed in the process from the nitrogen content of the coal. In many cases, it will be feasible and desirable to recover this in pure form for sale as a by-product. An alternative is to incinerate it or send it to the sulfur plant, although it is undesirable as a feed constituent in the Claus Plant since it will reduce the sulfur recovery.

Results of coal liquefaction indicate that most of the nitrogen remains in the heavy product, so the ammonia yield may be too low to make its recovery attractive. On the other hand, the high nitrogen content of the product, over 1%, will tend to cause a NO_x problem when it is burned so that special corrective measures may be needed.

5.4 Acid Gas Removal and Hydrogen Manufacture

Hydrogen is manufactured from part of the synthesis gas produced by gasification, after it has been scrubbed with amine and then caustic. This gas is heated, mixed with steam and passed over a shift catalyst to react the carbon monoxide to carbon dioxide and hydrogen. Carbon dioxide is then scrubbed out with hot potassium carbonate, using the proprietary Benfield process. (19) The raw synthesis gas contains considerable carbonyl sulfide and probably other forms of sulfur, which are not removed by amine scrubbing. The specific means of removing carbonyl sulfide is not described in the design. The caustic scrubbing step should give good cleanup, but will generate a large amount of spent caustic to dispose of, possibly more than 100 tpd, and a suitable process for reworking it would be needed, or more likely, a different process could be used for acid gas removal, such as hot carbonate, which would avoid this complication. A final methanation step is included to reduce the CO and CO_2 in the product hydrogen to 50 ppm each.

The largest effluents from this section are the atmospheric emissions from the furnaces which will be firing clean gas fuel. Little contribution to liquid or solid effluents will occur.

A water stream amounting to 27,168 lbs per hour is shown as an effluent from the Benfield CO_2 Removal Unit. It is also indicated that this may contain some carbonate solution, which may include a purge due to contaminants in the gas. The exact nature of this discharge needs to be defined and a satisfactory means of disposal worked out. The CO_2 stream removed by scrubbing is discharged to the atmosphere and presumably is a clean gas stream. However, this also must be defined more exactly, as it is sometimes necessary to provide further cleanup, or incineration on such streams. There are various water condensate streams from the hydrogen manufacturing section, but these are clean and can be used as boiler feed water make-up. The operation uses fixed beds of catalysts for shifting and methanation which will require replacements at intervals, and should be disposed of by returning to the manufacturer for re-working or disposal.

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5.5 Gasification and Slag Disposal

In this section, synthesis gas is made by reacting a slurry of the filter cake with steam and oxygen in a slagging gasifier. The filter cake contains residual ash from the coal amounting to 713 tons per day, together with 818 tpd of unreacted char, and is mixed with 1530 tpd of oil to form a pumpable slurry. Oxygen consumption is 1964 tpd while the total steam rate to gasification is 1837 tpd and the steam conversion is 65%.

Hot raw gas is cooled in a waste heat boiler and then scrubbed with recirculated water to remove dust. This water stream could present a difficult disposal problem since it is sour water containing particulates. In the specific design it is reused in the gasifier by first vaporizing it in an exchanger and then preheating to 1050°F in a furnace. The presence of particulates may cause plugging or erosion of the equipment, which could result in emissions to the environment. There may also be some tar or oil in the raw gas from gasification which would be scrubbed out by the water and would require disposal. If an alternative disposition of this stream is required, it could be passed through a settler to remove most of the particulates, and processed in a sour water stripper to remove ammonia and H_2S, and then to an oil separator, if required, before being discharged to a large settling pond. Water from this pond would then be returned through make-up water treating facilities to assure satisfactory operation of the steam generation and super-heating equipment.

There is a sour water stream from the raw gas clean-up section which is essentially free of particulates since it comes from a second stage condenser. This stream goes to a sour water stripper, and from there to a biox unit and then to the settling pond for reuse.

While the amounts of H_2S and ammonia have been reported for the water recovered from the raw gas, results from other coal conversion operations suggest that there will also be smaller amounts of other contaminants such as phenols, naphthalene, tar, cyanides, thiocyanates, etc. Information is needed on the amounts of these and on their rates of destruction in biological oxidation, in order to avoid problems such as the past experience on non-biodegradable detergents.

Information obtained on waste water from coking ovens (28) which should be somewhat comparable, show that certain compounds, such as thiocyanates, are decomposed very slowly, and various interactions also interfere with biological oxidation. Other compounds such as benzene and naphthalene can not be destroyed in a biox unit, and are not detected by the BOD and COD determinations.

Waste chemicals from water treating are neutralized and sent to the settling pond together with sludge and boiler blow down. Sediment from the pond could be reclaimed and disposed of along with the slag from gasification or fines from the tailing pond.

A major solid effluent from gasification is the slag. Molten ash leaves the bottom of the gasifier and is shattered by dropping into water to form a slurry, while the steam which is generated flows back into the gasifier. The slurry of slag is flashed and pumped to a storage pile in the coal feed storage area. There may be odors from the slag pile, as well as leachable materials such as sulfates or chlorides of calcium and magnesium etc. Additional information is needed on this subject.

Water drainage and storm run-off from this area should be collected and sent to a pond. The slag can probably be used as land fill or returned to the mine, provided odor, sulfur emissions, leachables, and dusting are acceptable.

5.6 Auxiliaries

One of the auxiliary facilities is the oxygen plant. It has no solid effluents and the only liquid effluent is condensed water which can be used for boiler feed water.

The sulfur plant produces marketable sulfur as a major product amounting to 317 tons per day. The basic Claus plant is conventional and techniques for controlling effluents are well established. The proprietary Beavon process is used to clean-up the tail gas by adding a reducing gas to convert sulfur compounds to H_2S, which can be removed by processes such as a Stretford type. The latter operation will generate liquid effluents, since some of the scrubbing solution must be purged in order to maintain activity. One way to dispose of it is by incineration.

Other auxiliaries include the usual generation of steam and power utilities, as well as a cooling tower and make-up water treating. Since the boiler is fired with clean product gas it does not generate solid effluents such as slag. Water treating produces most of the solid and liquid effluents from this utility area. Chemicals used in water treating include lime, aluminum sulfate, caustic soda and sulfuric acid. The amount of various chemicals used in the plant are summarized in Table 4. All of these will become effluents from the plant, part as dissolved salts in the effluent water and the remainder as sludge accumulated in the settling ponds. The sludge is relatively innocuous provided the leachables are not excessive, and it can be disposed of along with the slag from gasification.

The specific Parsons design shows a rather large waste water discharge amounting to 30% of the make-up. This includes boiler feed-water blow down, cooling tower blow down, sour water to biox, and the water from sanitary sewers. The total waste water discharge is 1,064 gpm compared to the make-up of 3,626 gpm. It appears that much of the water blow down could be treated and reused without reaching excessive levels of dissolved solids in the cooling tower circuit. Thus, the boiler blow down of 120 gpm can be used as make up to the cooling tower. Evaporation from the cooling tower is about 1800 gpm and it would be expected that the water blow down rate could be appreciable less than

the 600 gpm provided, without having too much build-up in dissolved solids. The best disposition of the waste water effluent from the plant will depend upon its location and the specific situation. It might be used to slurry the ash and solid refuse from coal cleaning for return to the mine, or it may be acceptable to discharge it to a river. Composition of the major components in this discharge water are needed in a specific case in order to determine whether the method of disposal will be satisfactory.

6. WATER TREATING AND WATER MAKE-UP

6.1 General

In considering the general problem of cleaning up waste water, it is convenient to think in terms of the types of materials present that can have detrimental effects if released to the environment. The following types of materials can be expected in waste water from the SRC process (and from many other coal conversion operations).

- particulates: ash, carbon, sludge
- soluble inorganics that would require evaporation if they must be removed: sodium chloride and sulfate, etc.
- suspended oil drops that may be removed by froth flotation (or settling if high density)
- soluble organics or inorganics that can be removed by stripping: butane, benzene, ammonia, hydrogen sulfide.
- soluble organics that have to be removed by extraction: phenol, cresols, etc.

The last item above warrants further comment, particularly for coal liquefaction since it has substantial amounts of oxygenated compounds in the product. If the product is used as boiler fuel, these would be burned and should be no problem; however, some of them will be appreciably soluble in the water layer separated from the reaction products, and will complicate the clean-up of this waste water stream for reuse or for discharge to the environment. An indication of the problem is shown by the solubilities of pertinent compounds in water, as given below for 68°F.

Benzene	0.18 wt. %
Toluene	0.05
Cresols	2.0
Phenol	8.3

These are for pure compounds, so the concentration in the actual water layer from coal liquefaction is probably much less, although data are not available. Such data should be obtained early in the pilot operation.

The point is that the concentration of many organics and inorganics in the water layer will be much too high to allow an effective biox clean-up directly. In the present design, the water layer is extracted with light oil to remove phenol, cresols, etc., which are recycled through hydrogenation to destroy them. Other processes are offered for this service, such as Phenosolvan (Lurgi). The water is also processed in a sour water stripper to remove more volatile organics and inorganics which are sent to the sulfur plant. At this point the contaminants are reduced to a low enough level so that biological oxidation should be effective (e.g. 10-50 ppm ea. NH_3, H_2S, phenol.)

6.2 Biological Clean-Up

As in many coal conversion operations, the SRC process generates water streams containing considerable quantities of chemicals which must be removed. In general, the types of chemicals are oxygenated compounds such as phenols and organic acids, nitrogen compounds such as cyanides and ammonia, and sulfur compounds including hydrogen sulfide and thiocyanates. Most of these can be removed to a low level using known techniques, for example, phenols can be extracted with a solvent and recovered or recycled, while ammonia and H_2S can be removed by a sour water stripper. However, in any practical operation there will still be a residual content of chemicals in the treated water which must be removed before the water can be discharged from the plant or reused in the process. In general, a biological oxidation (biox) system is depended upon to do the required clean-up in an activated sludge system, a trickling filter, or an aerated biox pond.

Biological oxidation has been found to be reasonably effective on many contaminants that are of concern in coal conversion operations, such as phenols, cyanides, ammonia, and H_2S. However, it is less effective on certain compounds such as thiocyanates. In one extensive test on waste water from coking plants (29) the percent removal in 24 hours was found to be as follows for various compounds.

Phenols	99.9%
Ammonia	90%
Chemical Oxygen Demand	80%
Cyanides	57%
Thiocyanates	17%

A further concern is that certain compounds may be completely resistant to biological degradation. An illustration of this is the past worldwide experience with synthetic detergents made from alkylated benzene. While these were very effective detergents, they were not degraded or decomposed in the environment and often resulted in severe foaming of large rivers and drinking water. It is quite possible that similar aromatic type materials or other compounds may be present in the waste water from coal gasification or coal liquefaction operations, and that these compounds may not be biodegradable. This also raises the question as to whether such materials can be determined by the usual analytical tests to measure BOD and COD. Tests made on waste water from coking overs (28) show that these are both problems, for example with benzene or naphthalene. One further example is the use of cresols to protect posts or telephone poles from decay in the ground. Such treatment is very effective for a period of many years and would seem to indicate that the treating material is extremely resistant to biological destruction.

There are biological systems that will consume stable materials such as asphalt, but the action is extremely slow as can be seen from the long life of asphalt roads. Similarly, the high resistance of heavy oils and carbonaceous materials is illustrated by the existence of extensive deposits of tar sands, oil shale, and coal.

A further point is that various chemicals are more or less soluble in water and very resistant to biological degradation. For example, the solubility of benzene in water is 1750 ppm at 68°F and it would probably not show up in the biological oxygen demand (BOD) determination, or as chemical oxygen demand (COD). Benzene specifically may be partially removed in a sour water stripper, but other compounds may not be removed.

Cresols are much more soluble in water than benzene (2-2.5 wt. %) while phenol dissolves to the extent of 8.3 wt. %. Since these are among the many types of compounds expected to be formed in the process, efficient recovery of them is necessary, together with a very thorough clean-up of all effluent streams to be sure that they do not result in serious environmental problems.

An important consideration is that biological systems may take weeks to become well established. Specific organisms are needed to consume the various types of compounds present. Moreover, careful balance is needed between the chemical loading and the available oxygen dissolved in the waste water. In many cases, additional aeration is needed to provide sufficient oxygen for the biological oxidation. In addition, nutrients such as nitrogen, phosphorous, iron, copper, molybdenum, etc. are also essential for cell growth. On the other hand, excessive amounts of these same elements can be highly toxic.

The importance of oxygen availability can be illustrated in more quantitative terms. A typical cell composition can be represented by the empirical relationship $C_5H_7O_2N$ (30). On this basis it takes at least 1/2 pound of oxygen per pound of hydrocarbon consumed, and over 2 pounds of oxygen per pound of nitrogen incorporated into the cell. Since the solubility of oxygen in water will be only 6 or 7 parts per million it follows that re-aeration of the waste water will be needed in most cases in order to maintain aerobic conditions. One way to do this is with floating aerators on the biox pond, using one of the many types being offered for this service.

Biological oxidation of ammonia requires additional food containing organic carbon for the organisms. It has been shown that methanol is suitable for this purpose. Thus, in some cases, it may be necessary to add either organic carbon or nitrogen compounds to provide the proper nutrient balance. It will, of course be difficult to maintain exactly the correct balance and to completely consume all of the different nutrient materials, therefore, very careful monitoring and adjustment of the nutrient balance may be necessary for an effective biox system.

Once it is established and stabilized, biological oxidation can be very effective. However, it will be sensitive to surges in input, for example an increase in inlet loading will increase the

oxygen consumption and can result in anaerobic conditions which would destroy the culture. On the other hand, a decrease in inlet loading would cause cells to die because of lack of food. Decomposition of the dead cells would then cause further problems. A variation in loading of more than 2 to 1 from normal can be expected to disrupt a biological system. This makes it difficult to accomodate upsets on the plant, or shutdowns for maintenance.

In general, the biox system can be a practical and satisfactory way to dispose of various contaminants that are present in small concentration and would be difficult to remove from waste water by stripping or extraction. In addition, use of activated carbon should be carefully considered for final clean-up of the water, and it may be needed in order to remove certain compounds that resist biological degradation or that are not removed completely by it. In any event, activated carbon may be useful in order to clean-up the water sufficiently so that it can be reused in the process. While activated carbon has been quite expensive in the past there are several indications that a low cost substitute may be available as a by-product from coal gasification. Tests have been made on the spent char from such operations, and the char has been quite effective for adsorbing such things as phenols.

6.3 Sludge Handling

In designing facilities for biological oxidation of waste water, consideration must be given to the resulting sludge to be handled and disposed of. By way of example, if the plant generates 1064 GPM of waste water containing 10 ppm ammonia, this could be expected to make roughly 0.5 tons per day of cellular material. It is difficult to concentrate such cellular sludge by settling, and the settled sludge may only be at 5% concentration in water. This would give 10 tpd of sludge (2 acre ft/yr) which might be disposed of along with the ash or slag from the coal. The sludge could be concentrated further by centrifuges or filters, and disposed of by incineration to recover its fuel value. Or it can be used for land-fill or soil conditioning provided it is shown that the particular sludge is suitable and does not result in offensive odors for example. Some sludges have been dried to a granular material which is sold for soil conditioning.

There are particular biological systems that are active only in the absence of oxygen (anaerobic). Such systems can decompose nitrates to nitrogen gas provided suitable organic carbon is also available, and at the same time generate methane and carbon dioxide. These systems can also decompose other nitrogen and sulfur compounds, resulting in strong offensive odors as is often the case for salt marshes and mud flats in littoral areas. Anaerobic systems provide one possible way to dispose of the cellular sludge from aerobic oxidation. It has been proposed to use such a system and then burn the off-gas from it as a source of valuable fuel. Unfortunately, the reaction rates for this are so slow that this approach may not always be practical.

Even though the waste water is cleaned-up and reused in the process, there will eventually be a limitation due to the increase in concentration of dissolved solids in the water such as sodium salts. If the net water effluent contains 2000 ppm of total dissolved solids, the concentration corresponds to 6% of that for sea water and is approaching what would be called brackish water. It would not be suitable for irrigation purposes.

In such cases the waste water may contain too much dissolved solids to allow discharging it to inland waters or rivers. If so, it may be necessary to send it to an evaporation pond where the salts would accumulate. If they cannot be sold or used it would seem logical to ultimately dispose of them in the ocean.

This specific design has a water make-up requirement of 3626 GPM. The amount of dissolved solids in it at 500 ppm is 3600 tons per year. At 100 lbs. per cubic foot this would correspond to about 2 acre feet per year for the dissolved solids alone. In addition, there is the sludge from water treating to remove calcium and hardness components, but this can probably be disposed of along with the coal ash, or used as landfill. The tons per day of such sludge may be equal to or several times that of the dissolved solids; however, it is normally much more bulky and contains considerable water, therefore, its volume can be many times that of the salts corresponding to dissolved solids.

6.4 Water Make-Up

When the concentration of dissolved solids in the available make-up water and the allowable concentration in the effluent water have been established, the minimum volume of make-up and effluent water can then be calculated. Both of these are directly proportional to the total amount of water consumed by chemical reactions or evaporated to the air in the plant. Water consumed by reactions such as gasification will generally be quite minor, so the major factor is evaporation of water in the cooling tower. Therefore, the cooling tower load will determine the water make-up requirement and the minimum amount of water effluent from the plant. Load on the cooling tower can be decreased by use of air fin exchangers which reject heat to the air as sensible heat rather than by evaporation of water. In addition, improvements in overall thermal efficiency of the process will decrease the total amount of heat that must be rejected, and will therefore tend to allow lower load on the cooling tower. Use of gas turbine drives rather than condensing steam turbines for compressors and for electric power generation can also reduce the overall load on the cooling tower.

7. THERMAL EFFICIENCY

Thermal efficiency for the base design is 64.0%, arrived at by dividing the heating value of salable products by the heating value of the coal fed to the liquefaction and utilities sections. Excluding the sulfur by-product lowers the efficiency to 63.0%. This does not allow for the coal used as fuel in the coal drying operation, which further reduces the overall efficiency to 60.3%.

Efficiency can be increased, as summarized in Table 5, by various adjustments which appear reasonable. More efficient use of heat in the coal dryer can cut the fuel requirement to about 1/3, giving a thermal efficiency of 62.1%. Re-examination of the heat effects in the preheat furnace and reactor further increases thermal efficiency to 64.6%. This allows for the heat released by the hydrogenation reaction which is equivalent to roughly 400°F temperature rise on the coal alone. Additional heat release from the water gas shift reaction of the syngas used in the base design is equivalent to another 150°F on the coal alone. Of course temperature rise would be less on the total slurry plus gas stream flowing through the reactor. In addition the coal should be available at perhaps 200°F from the coal dryer and this heat can be conserved rather than feeding the coal at ambient temperature.

It is possible that all heat needed for coal drying could be supplied by waste heat, for example in flue gas from the preheat furnace or from the utility boiler. If so, a thermal efficiency of 65.5% is calculated.

A combination of various potential improvements could increase the thermal efficiency to well over 70%. A major loss in efficiency results from hydrogen manufacture, since it has a thermal efficiency of only about 60-65%. At a hydrogen consumption of 3 wt. % on coal, the Btu contribution by hydrogen is about 15% of the coal heating value. It would seem that the hydrogen consumption could be reduced below the 3 wt. % used in the base design, without exceeding the sulfur content required in the product to meet present target sulfur emission for liquid fuels. The latter is 0.8 lbs. SO_2 per MM Btu, which would allow 0.6% sulfur in the total SRC product. However, future sulfur emission targets may be lower.

The base design includes some hydro-treating of the liquid products, corresponding to an average sulfur content of 0.4% on the total fuel product. Assuming that there are no operability or other limitations that necessitate hydro-treating, the reaction severity might be decreased in order to give a lower hydrogen consumption. Presumably, this would also make less light gas, which contributes to hydrogen requirement. By way of example, hydrogen consumption might be reduced from 3% to 2% on coal.

Table 5

SRC Process

Thermal Efficiency

Base design	64.0%
Excluding sulfur product	63.0%
And incl coal fuel to dryer	60.3%
More efficient coal dryer	62.1%
Revised reactor heat load	64.6%
If use waste heat in flue gas for coal drying	65.5%
With Potential Improvements	
Omit hydrotreating & distil.	
Cut H_2 consump. to ca 2%	Over 70%
Make H_2 from prod. gas	
Use pure H_2 to reactor	

An improvement in thermal efficiency will result if the hydrogen is made from the product gas by conventional steam reforming, instead of gasifying the char. One advantage is that the gas has a higher hydrogen to carbon ratio than char, and contains considerable free hydrogen. If carbon oxides are excluded from the reactor, then the hydrogen partial pressure will be increased for the same total pressure. Moreover, the gas is reformed by reaction with steam which also introduces hydrogen, rather than by reaction of carbon with pure oxygen. This means that there is less CO_2 removal required for a given hydrogen production. In addition, there are savings in compression since steam reforming operates at 400 psig compared to about 200 psig for the gasifier in the base design. Steam reforming, therefore, needs less compression of the product hydrogen, since the raw gas is available at higher pressure, moreover, in the alternative case, oxygen compression is required.

Low Btu syngas from gasifying the char can be used efficiently as plant fuel instead of converting it to hydrogen. This approach relaxes the requirements on a very difficult gas clean-up operation, compared to the stringent specifications for hydrogen manufacture.

Potential improvements are discussed in detail in a later sub-section of this report, and are summarized briefly in this paragraph. If char gasification is used to supply fuel gas for furnaces and utilities, then consideration can be given to using air instead of oxygen for gasification, and thereby eliminate the oxygen plant. This should be more efficient, and further evaluation appears warranted. In addition there may be more efficient ways to handle the filter cake. In the base design it is slurried with an equal weight of SRC product and then gasified. The amount of oil is 127,000 lbs per hour, or 33% on net products, and could contribute additional product from the plant provided a more efficient way of disposing of the char was used. One such alternative would be to coke the filter cake in a fluid bed at perhaps 1000°F to recover oil products overhead and then burn the fine residual char, or gasify it to make low Btu fuel gas. Another approach would be to burn the filter cake in a fluid bed furnace with stack gas clean-up as required.

As pointed out earlier a modification may be desirable on the handling and reuse of sour water, for example, the stream containing particulates removed in scrubbing the low Btu gas from gasification. If this water is not vaporized directly to make steam, then it may become necessary to provide sour water stripping on the entire sour water stream. This is a very large flow rate and could have a significant effect on plant thermal efficiency. Heat load for reboiling on the stripper would reduce thermal efficiency by about 1%, unless it can be supplied by heat which is otherwise wasted, e.g., to air fin exchangers.

8. SULFUR BALANCE

The fuel products from the process are indicated to be at or below the sulfur content needed to meet environmental regulations. Nearly all of the remaining sulfur from the coal feed ends up in the gas streams from which it can be removed by scrubbing. This may involve a separate reactor to convert compounds such as carbonyl sulfide to H_2S by hydrolysis, or they may be removed by hot carbonate scrubbing. Sulfur in the gas can then be reduced to a very low level so that all of the sulfur in the gas goes to the Claus plant, which with tail gas clean-up can give over 99% recovery.

There are a few other effluent streams containing sulfur but these are small. Sour water from the process will be stripped for odor control and the amount of sulfur discharge will be minor. Slag from gasification will also contain some sulfur. Since it leaves the gasifier in a molten condition the sulfur content may be acceptable but this needs to be checked out, as well as the possibility of secondary pollution from odor and leaching. These may depend upon the composition of coal ash, particularly calcium content. Distribution of sulfur in the products is shown in Table 6.

Claus tail gas is cleaned-up in the Beavon process by first reducing the sulfur compounds to H_2S, which is then scrubbed out by the Stretford process. The Stretford solution is regenerated by blowing with air and careful examination of potential contaminants in the effluent air is needed. Also the amount and composition of the purge solutions from the operation need to be defined, including sulfur content.

The coal dryer is not included in the above sulfur balance, on the basis that clean product gas will be used as fuel. If part of the dried coal were used to supply all of the fuel for coal drying then the sulfur emissions would be excessive. Instead, part of the product gas or the SRC product can be burned to give acceptable sulfur emission. As an alternative, heat could be supplied by using hot flue gas from one of the furnaces, or possibly warm air from air-fin exchangers. The fuel fired for coal drying is about 150 MM Btu per hour so that the maximum sulfur emission allowable would be 180 lbs SO_2 per hour.

Table 6

SRC Process

Sulfur Balance

	lb S/hr	%
In Coal Feed	27,987	100.0
In liquid products		
Heavy prod. (0.5% S)	1,215	4.3*
Plant fuel (0.5% S)	50	.2*
Light prod. (0.2% S)	240	.9*
	1,505	5.4
Acid gas to S plant		
From liquefaction	15,450	55.2
From hydrotreating	1,744	6.2
From gasification	9,053	32.4
From Sour Water	235	0.8
	26,482	94.6
Sulfur Plant		
Product Sulfur	26,417	94.4
In tail gas	65	0.2
	26,482	94.6
S plant recovery	$\frac{26,417}{26,482}$ =	99.8%
Total emission to environment - from conversion plant only		
Plant fuel and tail gas from sulfur plant	115	0.4%

* Ultimately emitted to atmosphere at location where these products are used as fuel.

9. TRACE ELEMENTS

The SRC product contains appreciable amounts of certain trace elements, especially titanium, and in many cases these constituents are high relative to their content in most heavy petroleum oils. Therefore, special consideration should be given now to their effects in order to avoid unexpected problems that could complicate application of the process in the future. Accompanying Table 7 gives published information on trace constituents in the SRC product compared to the coal feed. An outstanding feature is the high titanium content,up to 300 ppm. Although this is not considered to be one of the more toxic elements, the significance and impact of this need to be carefully evaluated. The content of beryllium, cobalt, copper, and lead is also significant and could cause pollution problems when the product is burned. Further study is needed to define these potential problems and the control measures if required. Beryllium is particularly toxic; consequently, it requires special attention in view of the high reported content of 0.7 ppm.

Some of the trace elements in the product may simply reflect residual ash; for example, the typical product contains perhaps 0.1% ash compared to 7% in the coal. Therefore, if the ash in the product is representative, it could contain 1/70 of the ash components in the original coal. This applies very roughly in the case of calcium, magnesium, and silicon. On the other hand, some ash components may become concentrated in the oil. Thus, the iron pyrite in the coal will decompose during hydrotreating, where the sulfur is removed as H_2S while the iron may be converted to a very finely divided or colloidal form. This could explain why the iron content of the SRC product is relatively high, or it could result from carbonyl formation, or simply corrosion of equipment.

Certain elements may be chemically associated with the oil; in the case of petroleum, it is well-known that vanadium and nickel form porpyhrin compounds which are surprisingly stable and oil soluble. These compounds are condensed ring structures with boiling points of 1000°F or higher, and are so stable that they can be distilled without decomposition. The SRC product contains significant amounts of vanadium and nickel, although they are still relatively low compared to many petroleum oils. The high titanium content of the SRC product is most unusual, and it would be very interesting to learn more about the form in which it occurs. It probably would be converted to the oxide during combustion and might cause fouling or corrosion problems such as are caused by vanadium in the case of heavy oil fuels.

The potassium content of the SRC product is indicated to be quite low, amounting to only a few tenths of a percent of the potassium in the coal. However, the sodium content is quite high and amounts to several percent of the sodium contained in the coal. Several other elements appear in the oil rather than being strongly retained in the ash. These include zinc, iron, copper, manganese and cobalt. It is interesting that these are all elements which have been established as being essential to plant life, so it is possible that they are intimately combined in the carbonaceous molecules of the coal.

Table 7

SRC Process

Analysis of Coal and Product Samples Composition, PPM

(Supplied by Pittsburg & Midway Coal Mining Co.)

Element	Atomic Absorption			Neutron Activation			Air Emission		
Sample *	1000 psig	Spl. 2 2000 psig	Spl. 3 Feed Coal	1000 psig	Spl. 2 2000 psig	Spl. 3 Feed Coal	1000 psig	Spl. 2 2000 psig	Spl. 3 Feed Coal
Aluminum							96.	130.	12000.
Antimony	< 4.	< 4.	< 4.	.25	.30	10.6			
Arsenic				1.4	.5	19.			
Barium							.22	.55	50.
Beryllium	0.7	0.4	09				< .4	< .2	< 10.
Bismuth							< .2	< .1	< 5.
Boron	100.	51.	94.				15.	36.	200.
Bromine							3.8	3.9	7.2
Cadmium	< .1	< .1	1.5				< 1.	< .7	< 33.
Calcium	180.	70.	3400.				100.	84.	4800.
Cobalt	2.2	0.8	17.	.35	.23	6.	< .4	< .2	< 10.
Copper	3.7	2.5	6.				1.1	3.9	8.6
Chromium	< 2.	< .2	31.	1.3	.88	38.	1.1	1.5	78.
Flucrine				<100.	<100.	300.			
Germanium							< .4	< .2	< 10.
Gold							< .4	< .2	< 10.
Iron	98.	161.	24000.				30.	160.	20000.
Lead	< 2.	.4	8.				< .4	< .2	< 10.
Lithium	< .02	< .02	7.4						
Magnesium	23.	9.	550.				20.	15.	890.
Manganese	3.	1.	39.				2.8	2.7	75.
Mercury	.05	.01	.05						
Molybdenum	< 50.	< 50.	< 50.				1.7	1.4	49.
Niobium							< 2.	< 1.	< 44.
Nickel	2.5	4.	29.				3.6	9.8	120.
Potassium	< 2.	6.	1300.	5.	17.	1790.			
Samarium				.36	.16	1.9			
Selenium				2.	<1.	7.			

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	Atomic Absorption			Neutron Activation			Air Emission		
	1000 psig	2000 psig	Feed Coal	1000 psig	2000 psig	Feed Coal	1000 psig	2000 psig	Feed Coal
Silicon				600.	900.	18000.			
Silver	< 2.	< 2.	< 2.				.02	.09	.8
Sodium	45.	25.	166.	30.	21.	367.	10.	20.	320.
Strontium							< .8	< .5	< 20.
Tantalum							< 2.	< .9	< 50.
Tellurium				1.4	0.6	5.8			
Thorium							< .8	< .5	< 20.
Tin				31.	9.	104.	2.9	2.0	40.
Titanium	300.	74.	460.				260.	160.	600.
Tungsten							< 1.	< .7	< 30.
Uranium							< 4.	< 2.	< 100.
Vanadium	17.	16.	175.				17.	12.	200.
Ytterbium				.39	.025	.51			
Zinc	6.	3.	39.	4.5	.8	42.			
Zirconium				2.0	1.1	6.3	5.4	3.9	35.

From an environmental standpoint much more information is needed on the trace elements and their fate upon combustion of the SRC product. Some of these may end up as fumes or fine dust which should be removed from the flue gas. In any event, it must be determined whether or not control measures are needed, and if so, they will have to be defined. The emission limitations have been specified by EPA for a number of toxic trace elements, and specifications for other elements are under consideration.

The discussion so far has dealt briefly with trace elements in the SRC product, pointing out that more extensive study will be needed to prevent unusual and unexpected complications. In addition, there are other aspects of the overall plant to be considered with regard to emission of trace elements. It is obvious that all trace elements in the coal feed must leave the plant either in the products, or in other gas, liquid, or solid effluents. It is not yet possible to make complete balances due to the early stage of process development, but all data necessary for accurate and complete balances on toxic or potentially toxic elements should be obtained in the pilot plant program.

Many of the effluents from the SRC plant are from conventional operations, such as process furnaces, utility boilers, waste water treating, and ash disposal. These are common, or at least similar, to other coal conversion operations or coal fired boilers, and the pollution aspects and controls have been discussed in previous reports in this series (1,2,3,4) or in other references (16,17,22,24).

A key step in the operation is gasification of char, with disposal of the resulting slag. This introduces questions of what happens to trace elements during gasification, what further information is needed to define the problem, and what control measures may be necessary. The same applies to the slag, including the question of whether leaching of components in the slag will be excessive when it is disposed of as landfill or in a mine. A discussion of these questions is included in the above references together with some of the available information on this subject and provides a basis for defining the problem, and for determining what additional information needs to be obtained during development of the process. For example, it is known that volatilization is very significant for certain elements such as mercury, selenium, arsenic, lead, cadmium, antimony, fluorine, bromine, boron, and zinc. Most of these volatile elements are also toxic.

Although elements are lost, information is needed as to where they will appear, and in what form (also vapor pressure, water solubility etc.). Such results will be needed for critical elements on all gasification processes used commercially, to define what recovery or separation may be required and to allow designing effective pollution control and disposal

facilities. It is possible that part of the volatilized elements will enter into side reactions in the presence of sulfur, phenols, and ammonia, ash, etc., and may be soluble in water or oil, but this will not be known until further information is available.

In some process designs for coal conversion operations, certain streams are disposed of by recycling to extinction through a reaction zone. For the SRC design, this is the case on the sour water from the liquefaction reactor and from gasification. It will be apparent that if certain trace elements are collected by this recycle stream, then they will tend to build-up due to recycling since they may not be able to escape. This could apply for example to volatile compounds of arsenic, lead, boron, and fluorine. More information is needed to define the problem, but some provision for separating and disposing of trace elements may have to be added.

10. PROCESS ALTERNATIVES

In examing the process to evaluate environmental impacts and thermal efficiency a number of alternatives were considered, some of which appear to have potential for improving these aspects of the process without involving unproven technology or requiring major new developments. Some of these are presented in this section for consideration and listed in Table 8.

The first item to consider in this category is the coal dryer. Excessive sulfur emission would result when using the coal fuel indicated in the base design. By substituting clean product gas as fuel this problem is overcome. It is still necessary to clean up the flue gas leaving the dryer system to remove particulates but this can be done using bag filters. Also the amount of fuel consumed in coal drying can be considerably reduced by reducing the amount of excess air. While this will increase the moisture content of flue gas and also the residual moisture in the dry coal, it should not be serious since water is required in the liquefaction reactor. The important consideration appears to be the ability to handle the dried coal as a powder and this should not be significantly affected.

As mentioned earlier, revising and optimizing the heat balance around the reactor and preheat furnace could increase the thermal efficiency by about 2.5%. Full advantage should be taken of the sensible heat in the coal leaving the dryer, at 200° F or higher. Also, the exothermic heat of reaction makes a considerable contribution. In the base design, a naphtha quench stream is injected at the furnace outlet and ahead of the liquefaction reactor in order to drop the temperature from 900° to 840° F. The purpose of this quench stream is not described, but if it is for controlling reactor temperature it may be that instead of using a quench, the excess heat could be recovered by indirect heat transfer to generate high pressure steam. For example, recycle slurry oil from the reactor could be passed through waste heat boilers, using a technique similar to that employed on catalytic cracking units in petroleum refineries. The amount of heat involved is about 150 MM Btu's per hour, corresponding to about 1.4% on thermal efficiency.

There are a number of other places in the base design where heat recovery might be improved. As one example, the product liquid is cooled in air-fin exchangers to 100°F, then it is reheated to be taken overhead in a flash zone, from which it is cooled, condensed, and then reheated and fed to fractionation. If feasible from a process standpoint, it would be more efficient to feed the product liquid directly to the fractionator.

In a number of cases, air-fin exchangers are used to reject heat that might otherwise be transferred to another stream for recovery. For example, the overhead condenser on the separator after the reactor removes 167 MM Btus per hour at a temperature level of 370°F to 130°F. Possibly some of this heat could be used effectively in acid gas removal, sour water stripping, or for boiler feed water preheat.

Table 8

SRC Process

Process Alternatives

1. Dryer on Coal

- coal fuel gives excessive sulfur emission, therefore change to gas fuel or use product liquid.
- high fuel consumption; design with low excess air can cut fuel consumption in half.

2. Liquefaction Reactor

- optimize reactor heat balance and conserve preheat in coal from dryer, to make large saving in fuel to preheat furnace.

3. Product Handling

- more efficient heat recovery. Avoid cooling and reheat steps on product liquid.
- transfer to process streams part of the heat now rejected to air at 370-130 F by airfin coolers, or use warm air for coal dryer or furnaces.

4. Gasification

- use incinerator to burn filter cake directly and recover fuel value rather than using gasifier, which consumes product liquid (to make slurry of cake) equal to 1/3 of net clean product liquids. Use stack gas cleanup on incinerator.

5. General Efficiency Items

- less excess air on furnaces, use heat pumps, pressure recovery, etc. as outlined.

6. Improve Thermal Efficiency to 70%

- burn filter cake instead of gasifying it.
- make hydrogen from product gas by steam reforming
- optimize reactor heat balance
- cut hydrogen consumption, omit product hydrotreating

7. Minimize Volume of Waste Water

- cleanup and reuse blowdown from cooling tower
- cleanup and reuse water from draining slag slurry

A major loss in efficiency is associated with gasifing the char, in that one-fourth of the potential liquid product is mixed with the filter cake to form a slurry so that it can be handled. The slurry contains equal weights of oil and cake, the oil amounting to 1,530 tons per day. The weight of char excluding ash is only 818 tons per day, so that there may be a better way to recover the fuel value from the filter cake. The best disposition would seem to be as fuel rather than for hydrogen manufacture, since the required hydrogen can be supplied easily from the product gas by conventional steam reforming. A practical and efficient system for burning the filter cake is needed, together with adequate pollution controls.

One possibility is to burn it in one of the fluid bed incinerators being offered for commercial use, together with a system to control emission of sulfur and particulates. In effect, pollution would be controlled on the flue gas, rather than by cleaning up the solid fuel. It will be apparent that stack gas clean-up has the advantage of controlling both particulates and sulfur emission at the same time. In addition it inherently has a higher thermal efficiency by permitting direct combustion of high sulfur solid fuel, without first processing it for example by gasification which may have a thermal efficiency of 65-70%. A number of processes are offered commercially for stack gas clean-up. Some of these use throw away limestone, while others use a regenerable salt to make a by-product from the recovered sulfur.(32)

Ways to reduce the overall energy consumption for the process are of a special interest in view of the present high cost of energy and fuel, which also has shifted the optimum design parameters. As one example, the use of heat pumps now becomes more attractive. These can best be applied when large amounts of heat are added and removed at slightly different temperatures. Such a situation exists on the amine regenerator, where the overhead condensor operates at perhaps 30 degrees higher temperature than the reboiler on the bottom. It is, therefore, possible to use a heat pump to compress the overhead vapors in order to raise the condensing temperature so that the heat of condensation can be used to provide the heat for reboiling. A second possible application of the heat pump is on the sour water stripper where a large amount of heat is required for reboiling and then must be removed in the overhead condenser at somewhat lower temperature. The economics of such heat pump applications is quite sensitive to the temperature difference between the reboiler and the overhead condensor, as well as to the cost of fuel. Therefore, potential applications have to be evaluated and optimized for each particular case. Since the technology involved is strictly conventional and straight forward, the necessary engineering evaluation can be made without the need for additional data.

To summarize, a substantial improvement in overall process efficiency should be possible by a combination of relatively straight forward modifications and changes, as follows:

(1) Burn the filter cake directly rather than gasify it.

(2) Make hydrogen by steam reforming of product gas.

(3) Optimize heat balance and heat recovery around the liquefaction reactor.

(4) Minimize hydrogen consumption in the reaction and omit hydrotreating to upgrade the products beyond boiler fuel requirement.

(5) Optimize heat and energy recovery, heat pumps, and general efficiency items.

In addition, these modifications will greatly reduce the formation of compounds such as carbonyl sulfide, and thereby simplify the acid gas removal system so that conventional amine scrubbing should be adequate.

One modification of the base design that merits special mention is reducing the amount of waste water effluent. This is a contaminated stream which will be difficult to clean-up and it is, therefore, desirable to minimize it. It appears that when this water has been cleaned up sufficiently to meet waste water effluent requirements, then it should also be suitable for reuse as make-up water. By using this approach in the present design, the waste water rate can cut considerably, perhaps in half, without exceeding reasonable levels of dissolved solids in the circulating water.

11. GENERAL EFFICIENCY ITEMS

Ways to reduce the overall energy consumption of a process are of special interest in view of the present high cost of energy and fuel. This process is a representative one to examine for efficiency improvement, in that is includes a wide range of operations including furnaces, heat exchangers, compressors, pumps, utilities, etc. In today's environment, a thorough examination is warranted to reoptimize conventional operations, and reduce overall energy requirements. In the course of this study, a number of such items have been considered which should have general application. These are listed below for consideration.

(1) Decrease excess air on furnaces. In many cases it has been practical to operate with as little as 5 percent excess air, generally with automatic control instrumentation.

(2) More extensive use of finned exchanger tubes in the convection section of furnaces, particularly those with gas fuel.

(3) Consider air preheating, especially on large furnaces.

(4) Use expanders to recover energy when gas must be depressured. This technique is well developed on air liquifaction plants. Similarly, energy can be recovered from high pressure liquids by using turbines--this can be used to advantage in acid gas removal systems, where a large volume of liquid is circulated between high and low pressure zones.

(5) It is generally desirable to supply low pressure steam, e.g. for reboilers, by first generating the steam at very high pressure and then depressuring it through a bleeder turbine to provide power for generating electricity, or for some other use. The incentive for higher pressure steam generation has increased considerably.

(6) In selecting turbines, more emphasis should be placed on turbine efficiency. For sizing pumps, excessive oversizing should be avoided as it leads to lower efficiency in normal operation.

(7) When a Claus plant is used for sulfur recovery it is advantageous to maintain a high concentration of H_2S in the feed in order to minimize the total gas volume to be handled. Keeping hydrocarbons and ammonia out of the feed gas will also help.

(8) To minimize fuel consumption, the temperature of the incinerator on the Claus plant tail gas should be no higher than necessary. In some cases a temperature as low as 1000°F has been used.

(9) The total circulation of cooling water can sometimes be decreased by reuse of the water. For example cooling water may leave the condenser on a turbine drive at 105°F, and by reusing this elsewhere it can be heated to say 120°F before going to the cooling tower, thereby decreasing the load on cooling tower fans and pumps.

(10) The use of heat pumps should be evaluated wherever there is a reasonably low temperature difference between the heating and cooling loads. This may apply to the regenerator of amine scrubbers used for acid gas removal, and on sour water strippers.

12. POTENTIAL IMPROVEMENTS

This section of the report discusses potential improvements that may require additional information and experimental work, in order to evaluate them fully. They are presented here and in Table 9 for consideration, and in some cases, have been mentioned in earlier sections of the report.

One of the largest heat requirements in the process is on the liquefaction reactor. A large preheat furnace is used and it may have a fouling and erosion problem due to handling a mixture of slurry containing heavy oil, together with recycle gas. It may be possible to reduce the heat load significantly. As one step, the coal feed might be preheated to about 500°F without excessive decomposition in a fluidized solids system at low pressure, and then lock hoppers would be used to introduce the coal to the high pressure system. As pointed out earlier, the heat of reaction in liquefaction corresponds to a temperature rise of about 400°F on the coal alone, which would then be sufficient to bring the coal to reaction temperature. The make-up hydrogen and recycle gas can be heated to reactor temperature or higher so that these do not contribute to the heat load. Then the only other large requirement is to reheat the recycle oil used to form the slurry. It may be possible to reduce the amount of this recycle oil since it is no longer necessary to form a slurry of the coal feed in order to transport it and pump it to high pressure. Instead the coal would be introduced into the reactor as a suspension in gas. If staging is not important in the reactor, it could be operated as a perfectly mixed reactor so that a high rate of oil recycle for temperature control is accomplished simply by the turbulent mixing within the reactor. On the other hand, if staging is desired.then reactor product slurry could be recycled to the inlet at a controlled rate. Rather than using mechanical pumps for this service which would present operating problems on the hot slurry, it is suggested that a gas lift system be used wherein pumping energy is supplied by gas bubbles rising through a vertical column of liquid, as is commonly used for handling corrosive liquids. Start-up of the reactor would be handled by adding oil to it, and then recirculating gas through the furnace to bring the reactor up to temperature.

In looking at the utility balance,it is seen that clean product gas is used as fuel in various furnaces, as well as for steam and power generations. It would be more efficient to first burn at least part of this fuel gas at high pressure, for use in flue gas turbines generating electricity. This equipment might be similar to that used by public utilities for stand-by power generation. The hot gases leaving the turbine-generator would then go to the furnace used for preheating. Most of the furnace heat loads in this design are at temperature levels of 900-1000°F or less and, therefore, this approach would appear to be feasible. As a further efficiency improvement item it is desirable to generate steam at high pressure wherever possible and then to use it in

Table 9

SRC Report

Potential Improvements

1. Changes to reduce heat load on reactor preheat furnace:

   - preheat coal to ca 500°F, feed directly to reactor via lockhoppers rather than as a slurry in oil.

   - preheat reactor gas to ca 1000°F and feed as a separate stream to reactor

   - recycle oil as required to reactor with little or no cooling, using "gas lift" for pumping.

2. Use low Btu gas from gasifying filter cake as plant fuel, instead of as a source of hydrogen. Make required high purity hydrogen by conventional steam reforming of product gas, thereby eliminating oxygen plant and decreasing the amount of CO_2 that must be rejected by acid gas removal.

3. Burn filter cake directly to recover fuel value, and avoid consuming potential clean liquid product needed to make a slurry that can be handled.

4. Use hydrolysis step on acid gas removal system in gasifier section, to convert COS and other sulfur compounds to H_2S so that essentially all sulfur can be removed by amine scrubbing, rather than depending on scrubbing with sodium hydroxide for cleanup.

5. Where fuel gas is burned in furnaces, consider combined-cycle system where the gas is used first in a gas turbine, and then goes to the furnace. By-product power could supply all electricity needed for process.

6. Explore potential for energy savings:

   - expanders to recover energy from gases upon depressuring

   - turbines to recover energy on depressuring liquids, especially in acid gas removal

   - heat pumps between overhead condenser and reboilers, especially on sour water stripper and acid gas removal

   - make use of air preheat from airfin coolers, for coal drying or to preheat combustion air on furnaces

bleeder turbines to supply lower pressure steam requirements, such as for reboiling in the acid gas removal system. Thus, steam might be generated at 600 to 1000 psig and depressured through bleeder turbines to supply 50 to 165 psig steam. A detailed utilities balance is justified in order to optimize this system.

One possibility for energy saving is to send the warm air discharged from air-fin exchangers to a furnace, where the advantage of preheated air would be obtained. An air preheat of 100-200°F might result, increasing furnace efficiency by 3-5%. A second possibility is to use the warm air for coal drying. It is interesting that the amount of heat from just one service, the air-fin condenser on the reactor outlet, is enough to provide all the heat required for coal drying.

Other ways to improve energy recovery also deserve thorough consideration. Pressure recovery will be particularly important on high pressure processes such as this. Gas streams from flash separators and the like can be depressured through expanders in order to recover energy. These could drive other equipment or be used to generate electricity. Similarly, when liquid streams are depressured they can be passed through turbines to recover energy; for example, on the amine scrubbers after gasification, 9000 gpm of liquid is recirculated between the absorber at 180 psig and the regenerator at 18 psig. Theoretical pumping work is 900 HP, much of which might be recovered.

One change that would increase energy requirement is on the handling of sour water containing particulates. In the base design this is evaporated by indirect heat exchange. If it should be necessary to clean-up this water stream before evaporating, then it would involve a large sour water stripper and the heat requirement for this could decrease thermal efficiency by about 1%. Steam is commonly used for reboilers in such service, but it should be kept in mind that a direct fired reboiler may be simpler and more efficient. The possible use of a heat pump on the sour water stripper has already been mentioned.

The fate of carbonyl sulfide, and sulfur compounds other than H_2S, in the gas needs to be clarified. This applies to both the liquefaction reactor and the gasifier. Compounds such as carbonyl sulfide are not removed effectively by the amine scrubbing used for acid gas removal. In the case of liquefaction, perhaps they will be recycled through the reactor and be converted to H_2S by hydrolysis. It may be preferrable to include a separate reactor to carry out this hydrolysis, using techniques described in the literature (18).

The gasification reaction also produces carbonyl sulfide, as well as other sulfur compounds. The raw gas is first scrubbed with amine but some of these sulfur compounds will not be removed. Caustic is not a good way to remove them because of the problem of spent caustic disposal or regeneration. Part of the scrubbed gas is used

to make pure hydrogen for hydrotreating and this part is further scrubbed with hot carbonate using the Benfield process. This will remove a large part of the carbonyl sulfide, but in the specific design case, the CO_2 stream which is purged to the atmosphere has a sulfur content that is excessive, and would need to be cleaned up, for example by molecular sieves or by scrubbing with limestone. A preferred route would be to use an effective hydrolysis reactor ahead of an amine scrubber, so as to convert all forms of sulfur in the raw gas to H_2S which can then be removed to any desired level. This would reduce to a nominal level the load on the caustic wash system used to remove sulfur compounds ahead of the shift reactor. As it stands, a large consumption of caustic would be needed to give the required sulfur removal. Not only is this costly, but it also poses a difficult problem of disposing of spent caustic.

A promising alternative is to use the low Btu gas from gasification as process fuel rather than as raw material for hydrogen manufacture. One advantage is that it then does not have to be cleaned-up as thoroughly from the standpoint of sulfur and particulates. For example, carbonyl sulfide may be less of a problem. Moreover, consideration can then be given to using air for gasification rather than pure oxygen, as may be more advantageous if the low Btu gas is used in a combined cycle type of system. This type of gasifier is well known, and several processes are being developed for commercial use.

There is considerable incentive to burn the filter cake directly, rather than to slurry it with a large amount of valuable product liquid and gasify the mixture. It should be possible to burn it in conventional incinerators, but there may be a question of operability on a fluid bed burner system in that the filter cake may agglomerate and form large chunks, rather than disintergrate into small particles when it hits the high temperature bed. If this is a problem, then it should be possible to burn the filter cake in a mechanically agitated furnace or in a rotary kiln. These techniques may not be as simple or efficient as a fluid bed boiler, but the important point is to avoid having to consume a large part of the product liquid in order to dispose of the residual char. Of equal importance is the fact that if the filter cake is burned, then there is no longer a need for the special gasification operation, which entails considerable new development and detracts from the basic efficiency of the process. Gasification adds an oxygen plant and extensive raw gas clean-up, both of which are high consumers of utilities.

13. PROCESS DETAILS

Other details on the process including utility requirements for fuel, power, water, and steam are shown in Tables 10-14.

Table 10

SRC Process

Fuel Balance

Description	Low Sulfur Fuel Needed MM Btu/hr
Coal Preparation (1)(3)	115
Coal Slurrying and Pumping	--
Coal Liquefaction and Filtration	1039.5
Dissolver Acid Gas Removal	--
Coal Liquefaction Product Distillation	92.3
Fuel Oil Hydrogenation	57.0
Naphtha Hydrogenation	11.6
Fuel Gas Sulfur Removal	--
Gasification	41.1
Acid Gas Removal	--
Shift Conversion	96.3
CO_2 Removal	--
Methanation	--
Sulfur Plant	78.3
Oxygen Plant	--
Instrument and Plant Air	--
Raw Water Treatment	--
Process Waste Water Treatment	--
Power Generation	926.0
Product Storage	--
Slag Removal System	--
Steam Generation (2)(3)	443
Low Sulfur Fuel Consumed	2900.1
Total Fuel Gas Produced	-2735.6
Additional Fuel Required (SRC Heavy Liquid Product)	164.5

NOTES:

(1) Plus 2700 lb/hr of dried coal, equiv. to 35 MM Btu/hr.

(2) Plus 9000 lb/hr of dried coal, equiv. to 115 MM Btu/hr.

(3) Average sulfur emission is 1.2 lb SO_2 MM Btu of gas plus coal fired by way of example, but specific regulations may call for lower levels.

Table 11

SRC Process

Power Consumption

Description	Operating Horsepower			
	Pumps	Compressors	Other	Total
Coal Preparation	--	--	6,000	6,000
Coal Slurrying and Pumping	350	--	62	412
Coal Liquefaction and Filtration	10,261	580	920	11,761
Dissolver Acid Gas Removal	630	--	--	630
Coal Liquefaction Product Distillation	105	--	240	345
Fuel Oil Hydrogenation	1,179	8,000	230	9,409
Naphtha Hydrogenation	76	620	50	746
Fuel Gas Sulfur Removal	493	--	--	493
Gasification	107	40	--	147
Acid Gas Removal	380	--	--	380
Shift Conversion	142	3,520	--	3,662
CO_2 Removal	32	--	180	212
Methanation	--	--	15	15
Sulfur Plant	1,504	--	1,416	2,920
Oxygen Plant	--	24,444	--	24,444
Instrument and Plant Air	--	800	--	800
Raw Water Treatment	6,845	--	1,251	8,097
Process Waste Water Treatment	160	--	60	220
Power Generation	--	--	--	--
Product Storage	524	--	--	524
Slag Removal System	--	--	--	--
Steam Generation	--	--	--	--
Total Horsepower				78,417
Equivalent electric power KW				58,500

Electrical Power for Lighting of Process and Outside Areas, Buildings and Warehouses - 5590 kW

Table 12

SRC Process

Cooling Water Required

Description	Cooling Water Circulated (gpm)
Coal Preparation	2,000
Coal Slurrying and Pumping	1,760
Coal Liquefaction and Filtration	32,676
Dissolver Acid Gas Removal	37,500
Coal Liquefaction Product Distillation	410
Fuel Oil Hydrogenation	2,259
Naphtha Hydrogenation	45
Fuel Gas Sulfur Removal	3,100
Gasification	6,209
Acid Gas Removal	17,220
Shift Conversion	422
CO_2 Removal	--
Methanation	80
Sulfur Plant	--
Oxygen Plant	17,400
Instrument and Plant Air	90
Raw Water Treatment	--
Process Waste Water Treatment	--
Power Generation	--
Product Storage	--
Slag Removal System	--
Steam Generation	--
Total	121,171
Raw Water Makeup	2,666

Table 13

SRC Process

Treated and Waste Water Balances

Use	Quantity (lb/hr)
Treated Water	
Process Water (net)	121,183
Boiler Feed Water Makeup	213,738
Potable Water	149,909
Cooling Tower Makeup	1,328,378
Total	1,813,208
	(3,626 gpm)
Waste Water	
Boiler Feed Water Blowdown	61,123
Cooling Tower Blowdown	301,555
Cooling Tower Evaporation and Drift	1,026,823
Sour Water to Bio Pond	19,606
Water to Sanitary Sewer	149,909
Total	1,559,016
Actual Waste Water Discharge	532,193
	(1,064 gpm)

Table 14

SRC Process

Steam Balance, lb/hr

Description	600 psig	150 psig	60 psig	15-25 psig
STEAM PRODUCED				
Coal Liquefaction and Filtration	124,840		155,230	
Coal Liquefaction Product Distillation				2,570
Gasification	388,579			5,250
Sulfur Plant		37,500	70,000	8,570
Raw Water Treatment (Deaerator)				19,400
Power Generation (Waste Heat Boiler)	472,960			
Steam Generation	242,331			
From 600 psig Steam			138,710	
From 150 psig Steam			4,490	
From Steam Turbines on Process Users			790,410	
Total	1,228,710	37,500	1,158,840	35,790
STEAM CONSUMED				
Coal Liquefaction and Filtration	443,000			
Dissolver Acid Gas Removal	207,000		705,600	
Coal Liquefaction Product Distillation			9,980	
Fuel Oil Hydrogenation	22,400			
Fuel Gas Sulfur Removal			60,060	
Gasification	77,600			
Acid Gas Removal	52,900		332,800	
CO_2	72,400			
Sulfur Plant	12,700		14,000	
Oxygen Plant	202,000			
Raw Water Treatment				35,790
Process Waste Water Treatment			26,400	
Reduction to 60 psig	138,710	4,490		
Steam Turbines on Process Users		28,010		
Product Storage Area		5,000		
Building Heating			10,000	
Total	1,228,710	37,500	1,158,840	35,790

14. TECHNOLOGY NEEDS

An important objective of this study is to point out areas where additional information is needed in order to define environmental problems and means for their control. Some of these have already been touched on in earlier sections of this report, while items common to other coal conversion operations such as coal preparation, drying, and gasification are discussed in previous reports in this series. A number of pertinent items are discussed below and summarized in Table 15.

(1) Further work is warranted on the coal cleaning operation to be sure that the very large amount of fine refuse from the tailing pond can be disposed of without secondary pollution problems due to leaching, dust, toxicity, etc.

(2) The basic coal gasification process has not yet been proven out for commercial use, and involves many research and development needs, as pointed out in other references for similar types of gasification operations. (1, 2, 3, 4)

(3) Information is needed on the fate of trace elements during liquefaction and gasification. Some data have been reported on trace elements in the SRC product, but information is also needed on compounds in the gas such as hydrogen fluoride, hydrogen chloride, in the water such as soluble forms of toxic metals, and in the ash. Trace materials in the coal such as selenium, lead, and arsenic etc. will probably vaporize and be removed in the gas clean-up section. The reducing atmosphere in the gasifier might release zinc metal, which has a boiling point of 1665°F. Ultimate disposal from the clean-up system will need to be worked out as more is learned about where these materials show up and in what form. Both the entrained char and the sour water are completely recycled to the gasifier, so trace elements may build up in these recycle streams and provide a convenient place to separate them.

Since hydrogen and carbon monoxide are present in the liquefaction and gasification system at high temperature and pressure, it is possible that compounds such as arsine and carbonyls may be formed.

Available analyses on the SRC product show an unusually high level of titanium. While this is not now considered to be one of the highly toxic elements, it is most important to consider what the impact may be on subsequent handling and use of the SRC product.

Table 15

SRC Process

Technology Needs

1. Coal preparation: an environmentally satisfactory way to dispose of large amounts of fine refuse from tailing pond on coal cleaning operations.

2. Coal dryer: a system to maximize fuel efficiency (and minimize vent gas volume), with simple, effective control over pollution from sulfur, dust, etc.

3. Development of 2-stage gasifier:

   - 1700 F zone: amount of tar, soot, trace elements, COS etc. in raw gas and effect on gas cleanup and acid gas removal.

   - 3000 F zone: slag quenching, particle size control, and slag removal and disposal.

4. Use of SRC product as clean fuel:

   - effect of high content of trace elements, especially titanium and beryllium.

   - effect of high nitrogen content on NO_x production.

5. Sour water cleanup from liquefaction and gasification:

   - practical technique to reuse sour water, for example by vaporizing it in exchanger or furnace to make process steam. Potential problems to be overcome are: fouling due to small amounts of oil, tar, solids, etc.; corrosion from H_2S, CO_2, etc.; erosion due to solid particles.

   - waste water cleanup to remove phenols and other oxygenated compounds, nitrogen and sulfur compounds, so that it can be returned as makeup water

   - demonstrate that biox system is practical on actual waste water composition, and that it is dependable for a commercial plant subject to upsets and startups.

6. Acid gas removal:

   - methods to hydrolyze COS etc. to H_2S so that they can be removed completely by amine scrubbing or by other techniques

   - a way to handle cyanides and thiocyanates so that they do not interfere with acid gas removal, or necessitate purging chemicals from the operation

   - a system that will provide a high concentration of H_2S (eg 25-50%) to the Claus sulfur plant, if one is used, so as to improve sulfur recovery and decrease the amount of tail gas.

Table 15 (continued)

7. Trace elements - where they appear, in what form, and suitable control measures:

   - on burning the liquid product
   - in the gasifier raw gas
   - in slag from the gasifier
   - in sour water from liquefaction and gasification
   - in refuse from coal cleaning

(4) When the SRC product is burned as fuel, trace elements in it will be released and may form vapors or fumes. Although the release of total particulates may be within the required 0.1 lbs. per MM Btu, there could be excessive release of certain trace elements such as beryllium, cobalt, or arsenic. This potential problem needs to be defined, together with clean-up and disposal methods if required.

The product is quite high in nitrogen content which can be expected to cause a considerable increase in production of nitrogen oxides during combustion. Since this effect cannot be predicted accurately, it should be measured in combustion tests.

It is apparent that actual combustion tests are needed on the product to determine what the environmental problems are, if any, so that control measures can be worked out as needed.

This is a new product and it should be examined carefully from the standpoint of handling and use. Due to its high content of oxygen and nitrogen, it may have a strong odor which could call for special control measures. In addition, it is known that coal tars are carcinogenic, consequently the products should be carefully evaluated from this standpoint.

(5) It will be very important to define an effective clean-up system for the sour water so that it can be reused to minimize the amount of make-up water required. This water may contain particulates in addition to ammonia, hydrogen sulfide, phenols, cyanides, and traces of oil and tar. The proposed reuse of this water to generate steam for the process is a very desirable objective to demonstrate. If this entire stream had to pass through sour water stripping and water treating, then it would increase the fuel requirement. Vaporizing the sour water to make process steam could have an adverse effect on plant service factor, and the resulting impact on the environment should be considered since emissions during start-up and upsets are often much worse than for normal operation. It would appear that developing ways to make useful steam directly from sour water represents a very important technological need.

A biox unit is used for final clean-up of the waste water, which may contain compounds that are quite resistant to biological destruction, such as cyanides, thiocyanates, phenols, and ammonia, as well as small amounts of oil or tar. There may also be some trace elements in soluble form that could affect biological activity, for example, copper is known to be a poison at concentrations of only a fraction of a ppm. Therefore, experimental work is needed on an actual water sample in order to be sure that the operation will be adequate, and should be included in the pilot plant program.

(6) Gasification of char has research and development needs similar to those for other coal gasification processes, as discussed extensively in previous reports of this series (1,2,3,4). The proposed gasifier is a modification in that it operates at 200 psig with two stages - an upper one at 1700°F and a lower slagging stage at 3000°F. Some 30% of the slurry to be gasified is introduced near the top of the 1700° zone, and it may be that some tar and possibly soot will be formed and appear in the raw gas; at least during startup, or upsets. Information is needed on this since if it occurs the raw gas clean-up and sour water processing will be more complicated than shown. The raw gas passes through a dry cyclone to collect char, which is then recycled to the gasifier since it is not converted completely in one pass. If a higher char conversion could be maintained in the gasifier, as for some other gasifiers, then this recycle stream would be decreased, and efficiency would improve by reducing the heat load on the gasifier.

Molten slag from the gasifier drops into water to shatter it into particles that will form a pumpable slurry. The particle size from this operation needs to be established, so that the exact nature of the slag can be defined, and its disposal or use evaluated. The slurry is sent to a drainage pile and information is needed on the contaminants in this water, both as regards particulates and soluble materials that are picked up from the slag.

(7) Filtration to separate ash from the product liquid is an essential part of the process which needs to be well defined. Overall efficiency would improve if it were not necessary to add product liquid to the filter cake in order to form a slurry that can be handled. One alternative is to burn the filter cake directly in a fluid bed combustor or a mechanically stirred kiln. A second possibility is to feed the filter cake to a fluidized coking reactor, on the basis that the oil content would be distilled out for recovery, and the cake would break-up into small particles. These char particles might then be gasified or burned by various conventional techniques with suitable gas clean-up. Research in this area of char disposal could result in a considerable increase in thermal efficiency for the process, and at the same time simplify the development by avoiding the need to demonstrate a novel gasification system with its complicated and difficult gas clean-up system.

If the char is directly burned as fuel instead of being gasified, then information is needed on the combustion operation and clean-up of the flue gas resulting from it. There will be particulates and sulfur present and probably also trace elements, but all of these can probably be controlled adequately by suitable scrubbing.

(8) The process uses acid gas removal on the gas from liquefaction, on the raw gas from gasification, and in hydrogen manufacture. While removal of hydrogen sulfide is conventional and straight forward, there will be other sulfur compounds and materials in these gas streams which will complicate the acid gas removal, including COS, cyanides and thiocyanates. If some of these combine with amines and are not regenerated by the normal procedures, a purge stream will be needed. The presence of phenols may also affect the operation. Data are needed in this area as to the amount of purge, its composition, and its disposition.

A further item for research in this general area of acid gas removal is to develop a simple and efficient process for removing all forms of sulfur selectively, while giving a concentrated feed to the sulfur plant, for example 50% or more H_2S. This would minimize the total amount of gas to be handled in the sulfur plant, improve sulfur recovery, and thermal efficiency.

(9) There is potential for an appreciable improvement in thermal efficiency by a modified operation of the liquefaction reactor and preheat furnace. The coal feed is mixed with recycled oil in order to form a pumpable slurry, introducing certain limitations. The amount of oil recycled is set at twice the weight of coal in order toform a slurry that can be handled and pumped. This may be considerably more oil than is needed to form a satisfactory slurry in the reactor itself. All of this recycle oil is cooled from furnace outlet temperature of 900°F, down to 550°F entering the slurry mixing tank. Moreover, the stream is depressured from 1000 psig down to essentially atmospheric pressure. Although the heat can be recovered and used, the overall operation is inefficient and requires considerable pumping.

A further limitation of this system is that the coal feed cannot be preheated because the slurry mix temperature would be too high. An alternative approach is to feed the coal directly into the reactor rather than pumping a slurry. This would involve a certain amount of development, since the present commercial lock hopper operations are at perhaps 500 psig and low temperature, but with this system it should be possible to preheat the coal to about 500 F without having volatiles given off. The proposed modification should result in a much smaller reactor preheat furnace, since it has been estimated that heat given off by the hydrogenation reaction is equivalent to about 400 F temperature rise on the coal alone.

15. QUALIFICATIONS

As pointed out, this study does not consider cost or economics. Also, areas such as coal mining and general offsites are excluded. These will be similar and common to all conversion operations.

The study is based on a specific process design and coal type, with modifications as discussed. Plant location is an important item of the basis and is not always specified in detail. It will affect items such as the air and water conditions available, and the type of pollution control needed. For example, this study is based on high sulfur eastern coal, although it can be used on low sulfur western coal. Because of variations in such basis items, great caution is needed in making comparisons between coal conversion processes since they are not on a completely comparable basis.

Some other conversion processes are intended to make SNG or low-Btu gas fuel, and may make appreciable amounts of by-products, such as tar, naphtha, phenols, and ammonia. Such variability further increases the difficulty of making meaningful comparisons between processes.

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